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BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of Pacific Gas & Electric Company to Revise Its Electric Marginal Costs, Revenue Allocation, and Rate Design. (U 39 M)	Application 16-06-013 (Filed June 30, 2016)

SAN DIEGO GAS & ELECTRIC COMPANY (U 902 E) FIXED COST REPORT AND WORKSHOP MATERIALS

AIMEE M. SMITH
8330 Century Park Court, CP32
San Diego, California 92123
Telephone: (858) 654-1644
Facsimile: (858) 654-1586
amsmith@semprautilities.com

Attorney for:
SAN DIEGO GAS & ELECTRIC COMPANY

October 6, 2016

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In accordance with the Rules of Practice and Procedure of the California Public Utilities Commission (the "Commission"), and the September 22, 2016 e-mail ruling of Administrative Law Judge ("ALJ") Jeanne M. McKinney ("ALJ Ruling"), San Diego Gas & Electric Company ("SDG&E") submits this fixed cost report addressing categories of fixed costs to be considered in developing a future fixed charge and related topics, as well as materials intended for use at the workshop scheduled to be held October 13, 2016.

In Decision ("D.") 15-07-001, the Commission considered IOU proposals for a new or increased "fixed charge" designed to collect certain fixed costs of providing service from all residential customers.[1/] The Commission concluded that in order to establish a fixed charge, certain requirements must be met, including "ensuring that the charge reflects appropriate costs, establishing a consistent methodology across utilities, and waiting until each utility has shifted to default [time-of-use ("TOU")] rates."[2/] It further determined that "[w]hile the record does not allow us to adopt a specific methodology for setting a fixed monthly charge, it does provide us with the evidence necessary to set the next procedural steps for reaching a resolution."[3/] The

1/ D.15-07-001, *mimeo*, p. 189.
2/ *Id*. at p. 190.
3/ *Id*. at p. 191.

decision outlines four conditions that must be met in order to permit further consideration of fixed charges.[4] Included in these four conditions is the following requirement:

> A [General Rate Case ("GRC")] Phase 2 decision . . . approving categories of fixed costs for consideration of a future fixed charge. To accomplish this, the first GRC Phase 2 filed by one of the three IOUs subsequent to today's decision shall include workshops on fixed charges. The assigned [Administrative Law Judge ("ALJ")] for that GRC, the assigned ALJ for R.12-06-013 and the Energy Division will set workshops to discuss a consistent methodology for potentially setting fixed charges based on fixed costs identified in each utility's individual GRC Phase 2 . . .[5]

The decision provides further, "the determination of which *categories* of costs the Commission determines should be permitted in a fixed charge should be considered precedential," and that "[t]he GRC Phase 2 applications for the other two IOUs should rely on the findings from the first decision."[6]

The instant case includes within its scope a workshop process to consider and develop a record to support a Commission decision adopting categories of fixed charges across the three IOUs. The above-referenced ALJ Ruling directs SDG&E to: (i) serve and file its proposed methodology and calculations for fixed costs and fixed charges in a format comparable to PG&E's Exhibit F/Fixed Cost Report; and (ii) serve and file its workshop materials. In accordance with this direction, SDG&E attaches hereto the following documents:

- **SDG&E Fixed Cost Report**
  - **ATTACHMENT A** (SDG&E 2016 GRC Phase 2 Marginal Distribution Costs – Direct Testimony)
  - **ATTACHMENT B** (SDG&E 2016 GRC Phase 2 Marginal Distribution Costs – Rebuttal Testimony)
  - **ATTACHMENT C** (SDG&E 2016 GRC Phase 2 Marginal Commodity Costs – Direct Testimony)

4/ *Id*. at pp. 191-193.
5/ D.15-07-001, *mimeo,* p. 192.
6/ *Id*. (Emphasis in original).

- **ATTACHMENT D** (SDG&E 2016 GRC Phase 2 Marginal Commodity Costs – Rebuttal Testimony
- **ATTACHMENT E** (Information Requested in ALJ Ruling)

- **SDG&E WORKSHOP MATERIALS**

Respectfully submitted this 6th day of October, 2016.

*/s/ Aimee M. Smith*___________________
AIMEE M. SMITH
8330 Century Park Court, CP32
San Diego, California 92123
Telephone: (858) 654-1644
Facsimile: (858) 654-1586
amsmith@semprautilities.com

Attorney for:
SAN DIEGO GAS & ELECTRIC COMPANY

Rulemaking No: A.16-06-013
Exhibit No: ___________
Date: October 6, 2016

SAN DIEGO GAS AND ELECTRIC COMPANY
FIXED COST REPORT

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

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I. INTRODUCTION

On October 7, 2013, Assembly Bill (AB) 327 was signed into law, removing the prior legislative restrictions on residential tiered rates and returning the authority to the California Public Utilities Commission (CPUC or Commission) to determine the design of residential electric rates including the ability to better align with cost-of-service and cost-causation and to approve "new, or expand existing, fixed charges for the purpose of collecting a reasonable portion of the fixed costs of providing electric service to residential customers."[1]

In Decision (D.) 15-07-001, the Commission considered IOU proposals for a new or increased "fixed charge" designed to collect certain fixed costs of providing service from all residential customers.[2] The Commission unanimously concluded that "[a] well-designed fixed charge representing a portion of the fixed customer-related costs to serve the individual residential customer could be reasonable,"[3] but that "[a]dopting a fixed charge at the same time as customers are also facing significant rate impacts associated with tier flattening would be inconsistent with our statutory duty to ensure reasonable rates."[4] The Commission determined that "[a] fixed charge should not be implemented until after the tier collapse is complete and after default time of use (TOU) has been implemented."[5]

The Commission concluded that in order to establish a fixed charge, certain requirements must be met, including "ensuring that the charge reflects appropriate costs, establishing a consistent methodology across utilities, and waiting until each utility has shifted to default TOU

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1 Public Utilities Code (Pub. Util. Code) Section 739.9(e). All code references herein are to the Public Utilities Code unless otherwise noted.

2 D.15-07-001, p. 189.

3 *Id*. at Conclusion of Law (COL) 16.

4 *Id*. at COL 17.

5 *Id*. at COL 18.

rates."[6] It further determined that "[w]hile the record does not allow us to adopt a specific methodology for setting a fixed monthly charge, it does provide us with the evidence necessary to set the next procedural steps for reaching a resolution."[7] The decision outlines four conditions that must be met in order to permit further consideration of fixed charges.[8] Specifically, the decision requires, *inter alia*, satisfaction of the following condition:

> A [General Rate Case ("GRC")] Phase 2 decision . . . approving categories of fixed costs for consideration of a future fixed charge. To accomplish this, the first GRC Phase 2 filed by one of the three IOUs subsequent to today's decision shall include workshops on fixed charges. The assigned [Administrative Law Judge ("ALJ")] for that GRC, the assigned ALJ for R.12-06-013 and the Energy Division will set workshops to discuss a consistent methodology for potentially setting fixed charges based on fixed costs identified in each utility's individual GRC Phase 2 . . .[9]

The decision provides further, "the determination of which *categories* of costs the Commission determines should be permitted in a fixed charge should be considered precedential," and that "[t]he GRC Phase 2 applications for the other two IOUs should rely on the findings from the first decision."[10] In accordance with the ruling issued by ALJ Stephen Roscow on November 5, 2015, the instant case includes within its scope a workshop process to consider and develop a record to support a Commission decision adopting categories of fixed charges across the three IOUs.

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[6] D.15-07-001, p. 190.

[7] *Id*. at p. 191.

[8] *Id*. at pp. 191-193.

[9] *Id*. at p. 192.

[10] D.15-07-001, p. 192 (Emphasis in original).

In compliance with D.15-07-001 and the ruling of Administrative Law Judge (ALJ), Jeanne M. McKinney,[11] San Diego Gas & Electric Company (SDG&E) presents this fixed cost report in order to support Commission approval of:

- The categories of fixed costs that are eligible to collect through a fixed charge in residential electric rates;
- The methodology for calculating monthly fixed charges for residential customers based on the approved fixed cost categories;[12]
- Whether or not fixed charges should differ between small and large customers;[13] and
- The process for developing the plans for ME&O for fixed charges.[14]

As ALJ McKinney has made clear, in the instant proceeding "**[we] are not deciding whether or not fixed charges are appropriate**. We are just deciding a methodology for the next time, if there is a next time, they are proposed in a residential rate-design case."[15] Therefore, the appropriateness of fixed charges will be considered in SDG&E's 2018 Rate Design Window (RDW) proceeding along with the implementation of default residential TOU.

The remainder of this report is organized as follows:

- Section II provides additional background on residential fixed charges

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[11] September 12, 2016 prehearing conference (PHC), Transcript, p. 28, line 25 through p. 29, line 15.

[12] The Commission-adopted methodology would be precedential for specific proposals made by SDG&E, Pacific Gas & Electric Company (PG&E), and Southern California Edison Company (SCE) in later, utility-specific, rate design proceedings.

[13] SDG&E interprets this directive to mean that the workshops should address the extent to which fixed costs to serve small customers differ from those to serve large customers, *not* whether proposed fixed charges should be different for small versus large customers. This is not the proceeding in which the Commission is considering fixed charge *proposals* per se.

[14] These plans will be vetted at the workshop (or workshops) to be scheduled after a prehearing conference is held to determine the schedule.

[15] September 12, 2016 PHC, Transcript, p. 13, lines 21-25 (emphasis added).

- Section III identifies the categories of fixed costs that are eligible to collect through a fixed charge in residential electric rates;
- Section IV discusses SDG&E's proposal for the methodology for calculating monthly fixed charges for residential customers based on the approved fixed cost categories;[16]
- Section V discusses whether or not fixed charges should differ between small and large customers;[17]
- Section VI discusses the process for developing the plans for ME&O for fixed charges;[18] and
- Section VII provides a summary of SDG&E's proposal.

In addition, this report contains the following attachments:

- Attachment A, the Direct Testimony of William G. Saxe, Chapter 6 in SDG&E's 2016 General Rate Case Phase 2 ("GRC P2") (Second Amended Application (A.) 15-04-012), which presents SDG&E's marginal distribution demand and customer cost study methodology;
- Attachment B, the Rebuttal Testimony of William G. Saxe, Chapter 5 in SDG&E's 2016 GRC P2, which presents SDG&E's most updated marginal distribution demand and customer costs;

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16 The Commission-adopted methodology would be precedential for specific proposals made by SDG&E, PG&E, and SCE in later, utility-specific, rate proceedings.

17 SDG&E interprets this directive to mean that the workshops should address the extent to which fixed costs to serve small customers differ from those to serve large customers, *not* whether proposed fixed charges should be different for small versus large customers. This is not the proceeding in which the Commission is considering fixed charge *proposals* per se.

18 These plans will be vetted at the workshop (or workshops) to be scheduled after a prehearing conference is held to determine the schedule.

- Attachment C, the Direct Testimony of Jeffrey J. Shaughnessy, Chapter 7 in SDG&E's 2016 GRC P2, which presents SDG&E's marginal energy costs and marginal generation capacity costs methodology;
- Attachment D, the Rebuttal Testimony of Jeffrey J. Shaughnessy, Chapter 6 in SDG&E's 2016 GRC P2, which presents SDG&E's most updated marginal energy costs and marginal generation capacity costs; and
- Attachment E, which responds to the direction provided in ALJ McKinney's September 22, 2016 email Ruling:
    - All three utilities should include information linking proposed fixed cost and fixed charge calculation to the GRC Phase 1 testimony or other applicable proceeding.
    - For data requests related to fixed cost and fixed charge calculations, each IOU should cite and link to GRC Phase 1 testimony or work papers. If requested, workpapers must be provided in Excel format. Workpapers provided to Energy Division staff must be in Excel format. The source of each number must be cited and described.

II. BACKGROUND

In the Commission's residential rate reform proceeding, Rulemaking (R.) 12-06-013, the Commission adopted the following ten Rate Design Principles (RDP).[19] Table 1 below presents the RDPs in four categories consistent with D.15-07-001: (1) cost of service, (2) affordable electricity, (3) conservation and (4) customer acceptance.

[19] R.12-06-013, pp. 27-28.

TABLE 1: RATE DESIGN PRINCIPLES

Cost Of Service RDP	Affordable Electricity RDP	Conservation RDP	Customer Acceptance RDP
(2) Rates should be based on marginal cost; (3) Rates should be based on cost-causation principles; (7) Rates should generally avoid cross-subsidies, unless the cross-subsidies appropriately support explicit state policy goals; (8) Incentives should be explicit and transparent; (9) Rates should encourage economically efficient decision-making.	(1) Low-income and medical baseline customers should have access to enough electricity to ensure basic needs (such as health and comfort) are met at an affordable cost.	(4) Rates should encourage conservation and energy efficiency; (5) Rates should encourage reduction of both coincident and non-coincident peak demand.	(6) Rates should be stable and understandable and provide customer choice; (10) Transitions to new rate structures should emphasize customer education and outreach that enhances customer understanding and acceptance of new rates, and minimizes and appropriately considers the bill impacts associated with such transitions.

The only way to achieve these multiple principles is through an accurate rate design that reflects how costs are incurred and through incentives that are addressed in a direct and transparent manner.

The rate design elements that are available are:

- **Non-variable Charges** that do not vary with customer load or consumption, such as monthly charges;
- **Variable Charges** such as: (1) Demand Charges which vary depending on customer's demand and when designed correctly are intended to "encourage reduction of both coincident and non-coincident peak demand" and (2) Energy Charges which vary depending on customer's consumption and when designed correctly are intended to "encourage conservation and energy efficiency."

The development of a cost-based rate requires the consideration of each of these charges. Failure to design rates structures that include each of these components will result in a rate that is not based on cost-causation principles and fails to set rates based on marginal cost. When all costs are recovered through an energy rate, this creates a rate design that fails to convey to customers the true cost of service, which is needed in order to inform economically efficient decision-making. For instance, today's residential tiered energy rates ($/kWh) sets a high price for energy consumption, resulting in an energy rate that greatly overstates the value of consumption and energy efficiency. The absence of any price signal for peak or non-coincident demand results in a rate design that understates the value of reductions in coincident and non-coincident peak demand.

SDG&E's rates recover the utility's costs of services related to commodity resources, distribution resources, transmission resources and public purpose programs (PPP). Under current effective rates, commodity services represent approximately 50% of total recovered costs, while distribution and transmission services represent 30% and 10%, respectively, and State and Commission mandate programs comprise the remaining 10% of recovered costs.[20] Additionally, energy provider rates address the recovery of the following categories of costs to serve customers:

- **Customer Costs:** These costs are independent of a customer's level of energy use and are required for each interconnected customer; therefore, customer costs should be recovered in a fixed or monthly charges ($/month). These costs include account set-up costs, billing and payment, credits and collections, customer contact, and metering services.
- **Energy Costs:** These costs are incurred on a variable basis (based on energy usage) with costs dependent on the time of delivery.
- **Capacity-related Costs:** These costs include Generation Capacity costs, Distribution Demand costs and Transmissions costs.

[20] PPP includes all non-commodity, distribution, and transmission costs.

- ***Generation Capacity Costs*** – These costs are not incurred on the basis of energy usage, but rather on the basis of meeting net peak capacity needs of the system; therefore, system capacity costs should be recovered in a demand charge consistent with the time period in which those costs occur, which is demand at the time of net system peak when additional capacity ($/peak-kW) may be required.
- ***Distribution Demand Costs*** – These costs are incurred independent of a customer's energy usage to reliably meet the local capacity needs of the combined maximum demand of customers served off a given circuit. Give the local nature of the load served by distribution circuits, circuit peak may not coincide with the time of net system peak.
- ***Transmission Costs*** – These costs are incurred to meet reliability requirements, which also include: (1) the need to address contingency conditions (e.g., the forced outage of one or more transmission lines that can occur at any time), (2) policy obligations (such as delivering and integrating renewable resources to meet Renewable Portfolio Standard (RPS) requirements), (3) economics (where the economic benefits to customers from reducing Local Capacity Requirements (LCR) or minimizing congestion-related costs offset the cost of the transmission upgrade) and (4) maintenance (such as aging infrastructure replacement and where new transmission is needed to allow other transmission facilities to be removed from service for maintenance without interruption of customer load).

III. CATEGORIES OF FIXED COSTS ELIGIBLE FOR FIXED CHARGES

AB 327 defines fixed charges as the following:

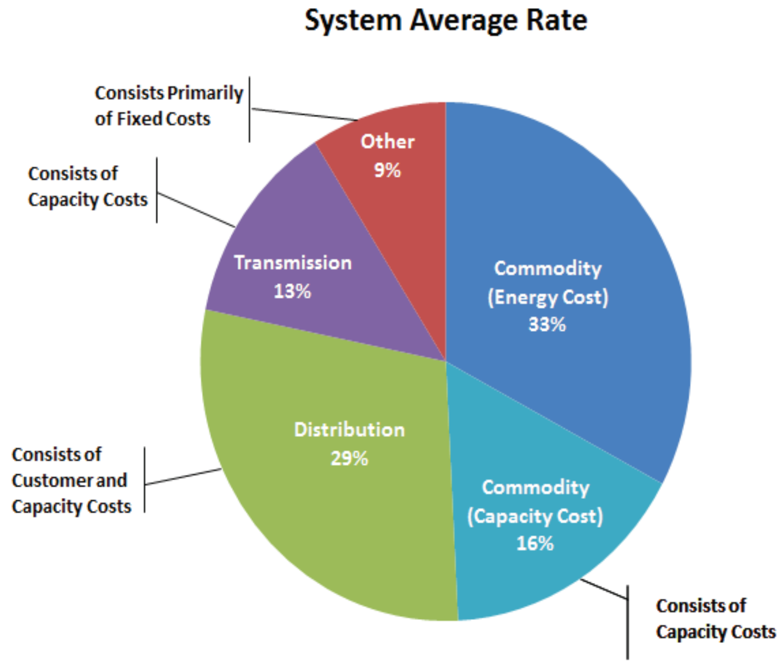
> "Fixed charge" means any fixed customer charge, basic service fee, demand differentiated basic service fee, demand charge, *or other charge not based upon the volume of electricity consumed*.[21]

This provision then identifies costs eligible for recovery through a residential fixed charge to include traditional customer charges (assessed on a per-customer-month basis), demand charges (assessed on a per-kilowatt (kW) basis), and any other charge that does not vary with a customer's consumption, regardless of function (*e.g.*, generation, distribution, etc.).

When reviewing the breakdown of the cost of utility services, only a third of the services recovered in electric utility rates are driven by the kWh energy usage of customers. The majority of the costs to serve customers are fixed. These costs are incurred independent of customer kWh usage and are driven either by: (1) the number of customers or (2) the capacity needs of customers, which result from their maximum load or demand of the customer.

[21] Pub. Util. Code Section 739.9. (Emphasis added).

CHART 1: BREAKOUT OF SYSTEM AVERAGE RATE[22]



As noted in Chart 1 above, only Commodity costs include any costs driven by a customer's kWh energy usage. Moreover, SDG&E's marginal commodity cost studies indicate that approximately 67% of Commodity costs, which represent less than 50% of the system average rate, are associated with marginal energy costs, meaning that, approximately, only 1/3 of the total utility cost of service is related to the kWh energy usage of customers. However, nearly 100% of costs for residential customers recovered through kWh energy rates. This current rate structure is not based in cost causation and results in a rate structure where high-demand or high-energy usage customers pay more than their actual cost-of-service while low-demand or low-usage customer pay less than their cost-of-service. Customers experience artificially high energy charges well in excess of marginal costs and therefore see inaccurate (and economically inefficient) price signals. Restructuring the recovery of costs in a rate structure to be representative of their incurred basis (*e.g.,* by including fixed charges in alignment with AB 327)

[22] Based on current effective rates (August 1, 2016).

will result in reductions in energy rates, more efficient price signals, and a move to a more equitable recovery of costs from customers.

IV. METHODOLOGY FOR FIXED CHARGES

Different methodologies exist for the development of marginal costs related to distribution and commodity services. A detailed description of how each of these marginal costs are developed under SDG&E's proposed methodologies is provided in SDG&E's marginal distribution[23] and marginal commodity[24] cost studies in its 2016 GRC Phase 2, and attached as Attachments A through D. Once the marginal costs are developed, an Equal Percent of Marginal Cost (EPMC) multiplier (or factor) is then applied to marginal costs to ensure full cost recovery of authorized revenue requirements.

Table 2 below identifies all the cost components currently included in residential rates, presenting both current recovery through energy only rates ($/kWh) as well as alternative recovery of the same revenues through a monthly service fee ($/month).

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[23] A.15-04-012, Direct Testimony of William G. Saxe, Chapter 6 (Attachment A), and Rebuttal Testimony of William G. Saxe, Chapter 5 (Attachment B).

[24] A.15-04-012, Direct Testimony of Jeffrey J. Shaughnessy, Chapter 7 (Attachment C), and Rebuttal Testimony of Jeffrey J. Shaughnessy, Chapter 6 (Attachment D).

TABLE 2: RESIDENTIAL RATE COST COMPONENTS[25,26]

		^	*		^	*
	$/kWh	kWh	Revenues ($)	# customers	$/month	Revenues ($)
Distribution	$0.08616	7,484,292,616	$644,815,861	1,273,685	$42.19	$644,815,861
Commodity Rate + DWR Credit	0.09909	7,372,950,325	730,567,166	1,271,884	47.87	730,567,166
Transmission**	0.02949	7,484,292,616	220,716,754	1,273,685	14.44	220,716,754
PPP	0.01238	7,484,292,616	92,658,647	1,273,685	6.06	92,658,647
ND	(0.00004)	7,484,292,616	(298,658)	1,273,685	(0.02)	(298,658)
CTC	0.00179	7,484,292,616	13,410,954	1,273,685	0.88	13,410,954
LGC	0.00039	7,484,292,616	2,911,916	1,273,685	0.19	2,911,916
TRAC	0.01704	7,484,292,616	127,537,366	1,273,685	8.34	127,537,366
GHG	(0.00609)	7,484,292,616	(45,575,268)	1,273,685	(2.98)	(45,575,268)
DWR-BC	0.00408	7,484,292,616	30,549,493	1,273,685	2.00	30,549,493
Total	**$0.24429**	**-**	**$1,817,294,230**	**-**	**$118.97**	**$1,817,294,230**

*Revenues are 8/1 unadjusted residential class averages.
**Includes Reliability Services (RS).
^Commodity Rate + DWR Credit is calculated using bundled customer-mo and sales from 8/1 consolidated rate model. All other rate components calculated using system customer-mo and sales from 8/1 consolidated rate model.

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25 Table 2 is based on authorized rates and sales effective August 1, 2016.

26 *Distribution* – recovers the following costs: (1) the costs of distributing power to customers which include power lines, poles, transformers, repair crews and emergency services; and (2) certain programs: California Solar Initiative (CSI), Self-Generation Incentive Program (SGIP), and Demand Response (DR);

Commodity component (EECC) – recovers the cost of energy delivered to customers.
Transmission – recovers the costs for the delivery of high-voltage electricity from power plants to distribution points near the customer site, which include the cost of high-voltage power lines and towers, as well as monitoring and control equipment and includes recovery of Transmission Access Charge Balancing Account Adjustment (TACBAA) and Transmission Revenue Balancing Account Adjustment (TRBAA);

Public Purpose Program (PPP) charge – recovers the costs of certain state-mandated programs: (1) low income programs; (2) energy efficiency programs; and (3) Electric Program Investment Charge (EPIC);

Nuclear Decommissioning (ND) – recovers the costs for the retirement of nuclear power plants;

Competition Transition Charge (CTC) – recovers costs for power plants and long term power contracts approved by state regulators that have been made uneconomical by the shift to competition;

Local Generation Charge (LGC) – recovers the costs associated with local generation;

Reliability Services (RS) – recovers the costs of generation facilities needed to meet Independent System Operator electric system reliability requirements;

Total Rate Adjustment Component (TRAC) – for residential customers, is the mechanism that provides rate subsidies to lower tier rates and recovers the cost of those subsidies through upper tier rates to ensure compliance with the glidepath for residential tiered rates adopted pursuant to D.15-07-001;

Department of Water Resources Bond Charge (DWR-BC) – recovers the costs of bonds issued by DWR to cover all costs of purchasing power during the energy crisis.

SDG&E's proposed definition of eligible costs for recovery through a residential fixed charge is consistent with AB 327 and includes all costs that do not vary with a customer's consumption. As identified in Chart 1 (in Section III above), only commodity energy costs vary by customer consumption and thereby all other costs should be eligible for recovery through a residential fixed charge. Table 3 below presents SDG&E's residential revenues by cost component as presented in Table 2 above into four categories: (1) customer-related costs, (2) capacity-related costs, (3) energy-related costs, and (4) additional costs (fixed and energy), based on the revenue allocation and marginal cost figures developed elsewhere in SDG&E's GRC Phase 2 application.

TABLE 3
SDG&E RESIDENTIAL FIXED COSTS AND FIXED CHARGES[27]

(A)	(B)	(C)	(D)	(E)	(F)=(C)+(D)+(E)	(G)=(B)-(F)	H	(I)=(C)+(D)+(G)
		Marginal Costs***				Additional Costs		
Residential[1]	Revenue Requirement ($ million)	Customer-Related ($ million)	Capacity-Related ($ million)	Energy-Related ($ million)	Total Marginal Cost ($ million)	Additional Fixed Costs ($ million)^	Additional Energy Costs ($ million)	Total Fixed Costs ($ million)
Distribution*	$644.8	$312.4	$302.5	$0	$614.9	$29.9	$0	$644.8
Commodity*	$730.6	$0	$272.6	$459.2	$731.8	-$1.3	$0	$271.4
Transmission****	$220.7	$0	$220.7	$0.0	$220.7	$0	$0	$220.7
PPP	$92.7	$0	$0	$0	$0	$92.7	$0	$92.7
ND	-$0.3	$0	$0	$0	$0	-$0.3	$0	-$0.3
CTC	$13.4	$0	$0	$0	$0	$13.4	$0	$13.4
LGC	$2.9	$0	$0	$0	$0	$2.9	$0	$2.9
TRAC	$127.5	$0	$0	$0	$0	$0	$127.5	$0
GHG	-$45.6	$0	$0	$0	$0	-$45.6	$0	-$45.6
DWR-BC	$30.5	$0	$0	$0	$0	$30.5	$0	$30.5
Total	$1,817.3	$312.4	$795.9	$459.2	$1,567.5	$122.3	$127.5	$1,230.6
$/cust-mo**	$118.97	$20.44	$52.10	$30.09	$102.62	$8.00	$8.34	$80.54

[1]Revenues are unadjusted class averages.
*Distribution and Commodity marginal costs are EPMC-adjusted.
**$/cust-mo is calculated by adding Commodity rate divided by bundled customer-mo and all other rate components by system customer-mo.
***EPMC-adjusted marginal customer costs differ from Table 4 as Table 3 is based on customer-mo and number of customers in the GRC P2 rebuttal testimony of William Saxe (Attachment B).
****Includes Reliability Services ("RS").
^Additional fixed costs in Distribution represent CSI, SGIP, and DR costs. Additional fixed costs in Commodity rate represent the DWR-BC credit.

Column B of Table 3 above identifies the total residential distribution revenues of $644.8 million. Residential marginal distribution costs, shown in Column F, total $614.9 million, leaving a difference of $29.9 million, the recovery of CSI, SGIP, and DR, which are included in the additional fixed cost category, shown in Column G. Column B also identified the total residential commodity revenues of $ $730.6 million which includes residential marginal

[27] Distribution Customer/Capacity from Saxe 2016 GRC P2 Rebuttal Workpapers, Commodity Energy/Capacity from Shaughnessy 2016 GRC P2 Workpapers, all other revenues from unadjusted Class Average Rates of 8/1/2016 Consolidated Model.

commodity costs, shown in column F, total $731.8 million and -$1.3 million associated with the DWR-BC credit. The costs of utility service included in Marginal Cost include costs of Distribution, Commodity and Transmission services by the following cost categories: (1) customer-related costs (marginal customer costs, Column C), (2) capacity-related costs (marginal capacity costs, Column D), and energy-related costs (marginal energy costs, Column E). Column I displays SDG&E's proposal for total eligible costs fixed, calculated by summing the customer-related and capacity-related costs in Columns C and D and the additional fixed costs in Column G, yielding a residential class fixed cost estimate of $1,230.6 million, or $80.54 per month.

A. Distribution

The infrastructure costs within the distribution rate component include (i) customer-related costs; and (ii) distribution demand-related costs. Cost-based recovery of distribution costs requires, at a minimum, that distribution costs no longer be recovered through energy rates, since none of the distribution-related costs are variable or dependent upon the energy used by customers, and instead represent the costs needed to meet new demand on the distribution grid.

1. Distribution Customer-Related Costs

Customer-related costs include the costs of ensuring that customers are ready to receive services from the utility before they even begin to use electricity, also described as "curb to meter" services. These costs are incurred independently of the amount of energy a customer uses, and are incurred on a per customer basis, and therefore should be collected on a $/month basis to reflect cost-causation. These costs include:

1) The cost of the final transformer, which step down voltage to levels that are usable and more safe;

2) The cost of the services lines, which connect individual customers to their service transformer; and

3) The cost of the meter, which provides the ability to measure customers' energy and load.

The cost of customer services, represents costs for such activities as customer service field, advanced metering, billing, credit and collections, branch office, customer contact center, residential customer services, commercial and industrial services, communications, and customer programs. SDG&E proposes the Rental method for determining the marginal distribution customer costs and is presented in greater detail in SDG&E's 2016 GRC Phase 2 marginal distribution cost direct and rebuttal testimony provided in Attachments A and B.

The marginal customer costs shown in Column C of Table 4 below represent the additional costs incurred by SDG&E when a new residential customer is added, and clearly should be included in estimating fixed costs. Marginal customer costs are typically made up of two categories of costs: (1) Customer Accounts/Services costs; and (2) new connection costs. Table 4 displays the marginal cost of both Customer Accounts/Services costs and new connection costs. Column B of Table 4 provides a breakdown of each of the components of marginal customer cost items in terms of dollars per customer-year, and Column C provides an EPMC-adjusted marginal cost per customer-year. SDG&E estimates the Customer Accounts/Services component of EPMC-adjusted marginal customer cost to be $46.36 per customer-year and the new connection cost component to be $202.91 per customer-year, for a total marginal customer cost for residential of $249.27. Columns C and D divide each number in Columns B and C, respectively, by 12 months to display the marginal cost and EPMC-adjusted marginal cost of each component per customer-month.

TABLE 4
SDG&E ESTIMATED RESIDENTIAL MARGINAL CUSTOMER COSTS

[A] Marginal Customer Costs	[B] Costs ($/cust-yr)	[C] EPMC-adjusted Costs ($/cust-yr)*	[C] Costs ($/cust-mo)	[D] EPMC-adjusted Costs ($/cust-mo)*
Customer Accounts/Services Costs				
Customer Services Field	$3.70	$6.06	$0.31	$0.50
Advanced Metering	$1.75	$2.86	$0.15	$0.24
Billing	$1.80	$2.95	$0.15	$0.25
Credit & Collections	$1.32	$2.17	$0.11	$0.18
Remittance Processing	$2.47	$4.05	$0.21	$0.34
Branch Offices	$1.03	$1.69	$0.09	$0.14
Customer Contact Center Operations	$4.69	$7.68	$0.39	$0.64
Customer Contact Center Support	$1.18	$1.94	$0.10	$0.16
Residential Customer Services	$3.97	$6.51	$0.33	$0.54
Communication, Research & Web	$4.94	$8.10	$0.41	$0.68
Customer Programs & Projects	$0.66	$1.09	$0.06	$0.09
Other Office	$0.37	$0.60	$0.03	$0.05
Shared	$0.40	$0.65	$0.03	$0.05
Total Customer Accounts/Services Costs	**$28.29**	**$46.36**	**$2.36**	**$3.86**
New Connection Costs				
Annualized Transformer, Service & Meter Costs	$93.56	$153.35	$7.80	$12.78
O&M Costs	$30.24	$49.56	$2.52	$4.13
Total New Connection Costs	**$123.80**	**$202.91**	**$10.32**	**$16.91**
Total Marginal Customer Costs	**$152.09**	**$249.27**	**$12.67**	**$20.77**

*EPMC-adjusted marginal customer costs differ from Table 3 as Table 4 is based on customer-months and number of customers in the GRC P2 rebuttal testimony of William Saxe.

2. Distribution Demand–Related Costs

Distribution demand costs include the costs of the grid that are needed to deliver electric services to the customer. These costs ensure the ability to deliver energy services, and as such are impacted by customer load and customer generation. Therefore, these costs should be recovered on a $/kW-non-coincident demand (NCD) basis to reflect cost-causation. Distribution demand costs include the following:

1) Feeders and Local Distribution: the costs associated with the primary distribution system which consist of switches, conductors, capacitors, line regulators, insulators, poles, vaults, conduits, fuses, etc.; and
2) Substation: the costs associated with the point of conversion from transmission to distribution voltages occurs which consists of transformers, circuit breakers, switches, insulators, bus work, control houses, system protection, etc.

SDG&E proposes the National Economic Research Associates (NERA) Regression Method for determining the marginal distribution demand costs and is presented in greater detail in Attachments A and B.

B. Commodity

Marginal commodity costs are the incremental electric commodity costs incurred on behalf of utility customers, and are composed of marginal energy costs and marginal generation capacity costs. Marginal energy costs (MEC) are the added energy costs incurred to meet electricity consumption. Marginal generation capacity costs (MGCC) relate to the added costs incurred to meet electric demand. MEC are the projected energy costs incurred to meet electricity consumption. Since SDG&E transacts in the California Independent System Operator (CAISO) markets, the marginal energy costs are based on monthly electric forward market prices specific to South Path-15 (SP-15) and an annual hourly profile of electricity prices representative of the San Diego area. A Renewable Portfolio Standard (RPS) adder is also included since added load requires added renewable energy under the RPS.

MGCC relate to the added costs incurred to meet electric demand. MGCC are calculated based on long-term considerations and are based on the net cost of new entry of a combustion turbine (CT), the long-term cost of adding new capacity. This amount is equal to the fixed costs of a CT less expected profits from energy and ancillary service markets. SDG&E's proposed methodology for the determination of marginal energy costs and marginal generation capacity costs are presented in more detail in Attachments C and D.

As shown in Table 3, SDG&E's generation revenue requirement for residential customers is $730.6 million, displayed in Column B. The marginal cost of generation is composed of:

- Marginal Generation Capacity Costs – the incremental cost associated with adding a kW of generation capacity; and
- Marginal Energy Costs – the incremental cost of serving an additional kWh of energy.

Marginal energy costs vary with customer usage by TOU period, and are not fixed costs. Marginal generation capacity costs vary with kW demands and so would appropriately be collected with demand charges. However, since residential customers do not pay demand charges, an argument can be made that some portion of these costs would be appropriately collected in a fixed charge (or one which varied in discrete increments based upon a customer's maximum kW demand), rather than 100 percent through energy charges.[28] In its proposal here, SDG&E has included marginal capacity costs of $271.4million in its estimate of fixed generation costs, as shown in Column I.

[28] A detailed description of SDG&E's marginal generation capacity and energy costs can be found in Attachments C and D.

C. Non-bypassable Charges

D.13-10-019 defines non-bypassable charges as transmission charge, Public Purpose Program Charge, Nuclear Decommissioning Charge, Competition Transition Charge, New System Generation Charge,[29] Department of Water Resources bond charge, and the Power Cost Indifference Amount applicable only to DA and CCA customers.[30] In order to be truly non-bypassable, these costs require recovery through a fixed charge. While different Commission decisions define non-bypassable charges slightly differently, for the purposes of determining costs *eligible* for recovery through a fixed charge, SDG&E believe it is appropriate to use the broadest definition.

The revenue requirement associated with NBCs, which does not vary with usage, is $314.4 million. There are no marginal costs associated with transmission,[31] PPP, ND, CTC, Local Generation Charge (LGC),[32] GHG, and DWR-BC costs, so these full amounts represents fixed costs, as shown in Columns G and H.

D. Total Fixed Cost Estimate

The 'Total' row of Table 3 displays the total residential revenues and fixed cost estimates. The total residential revenues are $1,817.3 million, with eligible fixed costs of $1,230.6 million. Dividing this fixed cost estimate by SDG&E's estimated 15 million annual customer-months yields an average fixed cost per residential customer of $80.54.

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29 SDG&E's New System Generation Charge is called Local Generation Charge (LGC).

30 D.13-10-019, p. 3, note 2.

31 Includes RS (Reliability Services)

32 SDG&E's New System Generation Charge is called Local Generation Charge (LGC).

E. SDG&E Proposals

- SDG&E's proposal for eligible costs to be recovered in a residential fixed charge is to include all costs that do not vary with customer's consumption regardless of function, which includes all of distribution, commodity capacity and all non-bypassable charges broadly defined as Transmission[33] charge, Public Purpose Program Charge, Nuclear Decommissioning Charge, Competition Transition Charge, New System Generation Charge[34], Department of Water Resources Bond Charge, and the Power Cost Indifference Amount applicable only to DA and CCA customers.
- SDG&E proposes the Rental method for determining the marginal distribution customer costs and is presented in greater detail in Attachments A and B.
- SDG&E proposes the NERA Regression Method for determining the marginal distribution demand costs and is presented in greater detail n Attachments A and B.

V. DIFFERENTIATION OF FIXED CHARGES FOR SMALL AND LARGE CUSTOMERS

AB 327 defines a fixed charge as "any fixed customer charge, basic service fee, demand differentiated basic service fee, demand charge, or other charge not based upon the volume of electricity consumed."[35] Charges not based upon the volume of electricity consumed then include charges that may vary by customer size. As discussed above, portions of distribution (Distribution Demand-related costs) and Commodity (Generation Capacity Costs) costs as well

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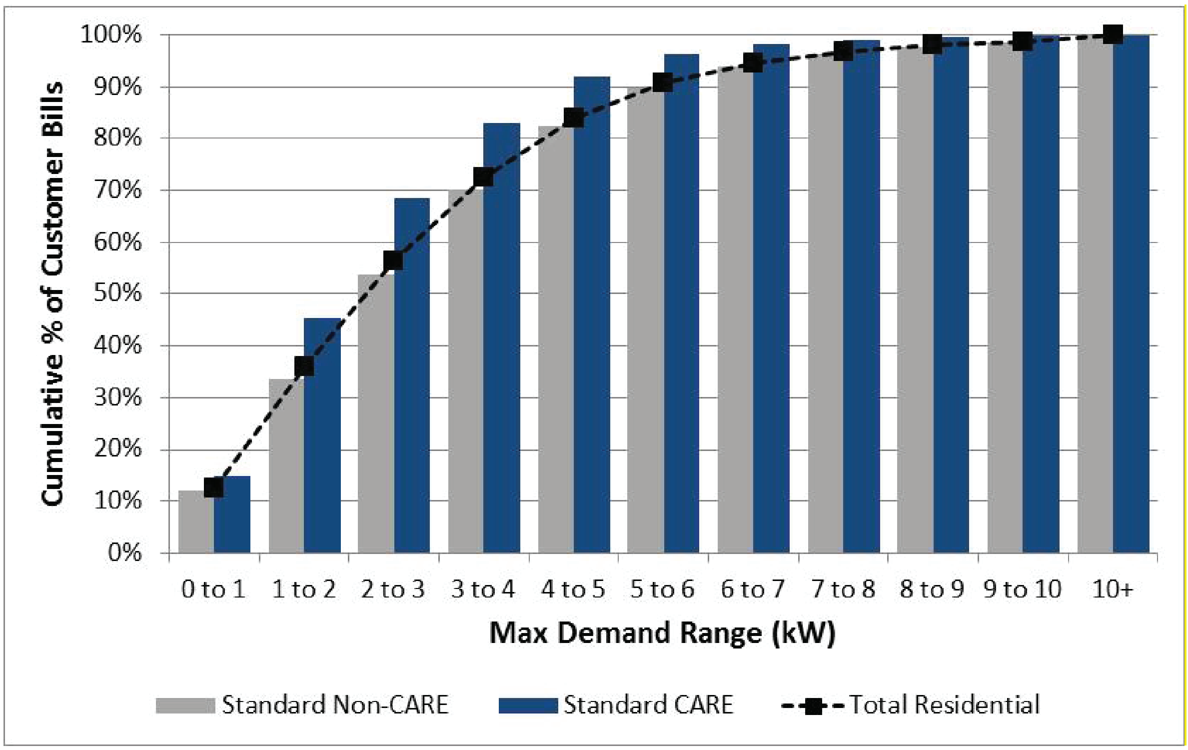
[33] Includes RS.

[34] SDG&E's New System Generation Charge is called Local Generation Charge (LGC).

[35] Pub. Util. Code Section 739.9(a).

as transmission costs are capacity driven and as a result are appropriate to vary with a customer's demand. Chart 2 below shows the distribution of hourly maximum demand for residential customers. 57% of separately metered residential customers had demand less than 3 kW. 91% of separately metered residential customers had demand less than 6 kW.

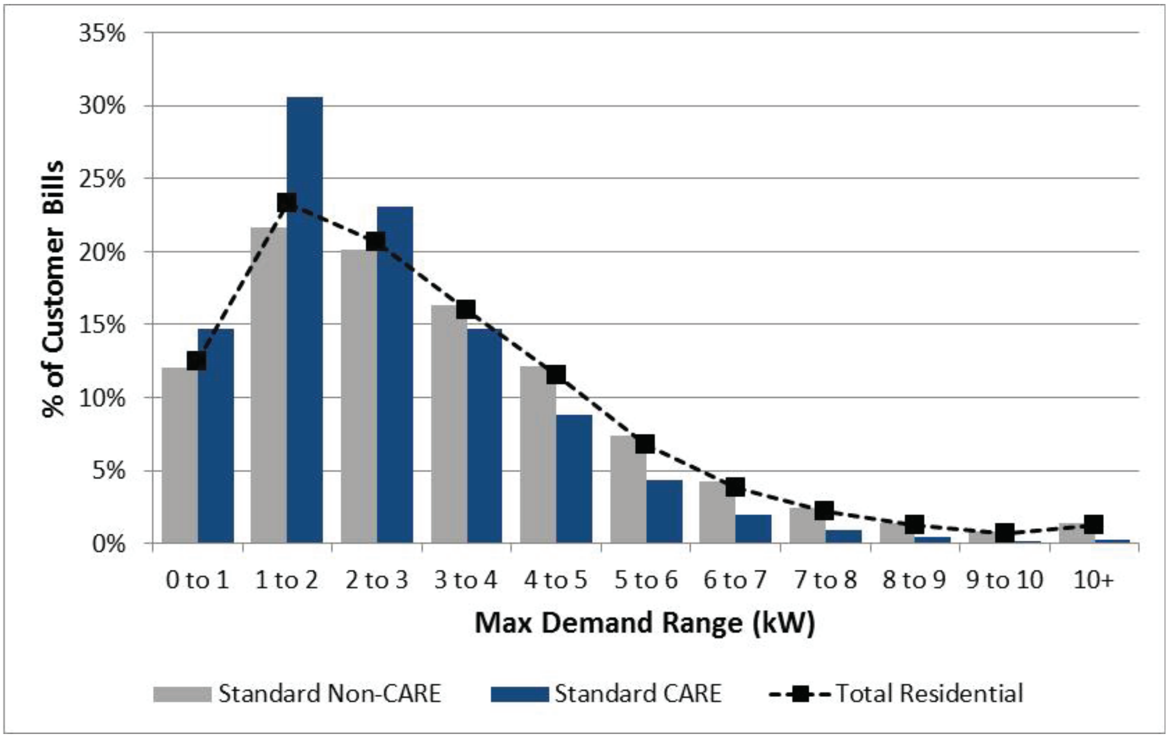
CHART 2: MAXIMUM DEMAND DISTRIBUTION FOR RESIDENTIAL CUSTOMERS[36]



The distribution of the percentage of residential customers by hourly maximum demand is presented below in Chart 3 below.

[36] Distribution time period is calendar year 2015.

CHART 3: RESIDENTIAL CUSTOMER DISTRIBUTION BY MAXIMUM DEMAND[37]



VI. PROCESS FOR THE DEVELOPMENT OF MARTKETING, EDUCATION AND OUTREACH (ME&O) PLANS

SDG&E agrees with PG&E that careful evaluation of the customer education and outreach needed to support rate design changes is critical. Any communication to customers about fixed charges or further rate changes should be aligned with messaging customers will be receiving about TOU rates and other significant residential electric rate changes.

VII. CONCLUSION

As SDG&E prepares to file its 2018 RDW proceeding, in order to provide options that meet the different and rapidly changing needs of individual customers, SDG&E believes the energy company should have full latitude to define fixed charges as stated in AB 327. This is the basis on which SDG&E proposes to base its fixed cost methodology. The utility has identified the fixed costs of providing service to residential customers "not based on the volume of electricity

[37] Distribution time period is calendar year 2015.

consumed,"[38] including costs that do not vary with usage as well as costs included in marginal cost analyses. By reducing the recovery of customer-related distribution costs from energy rates, customers will have more accurate price signals to allow for the investment in DER technologies in a manner that minimizes cost shifts to other customers.

38 Pub. Util. Code Section 739.9(a).

<u>FIXED COST REPORT - ATTACHMENT A</u>

SDG&E 2016 GRC PHASE 2 MARGINAL DISTRIBUTION COSTS

DIRECT TESTIMONY

Application of SAN DIEGO GAS & ELECTRIC COMPANY (U 902 E) For Authority To Update Marginal Costs, Cost Allocation, And Electric Rate Design.

Application: 15-04-012
Exhibit No.: SDG&E-06

PREPARED DIRECT TESTIMONY OF

WILLIAM G. SAXE

ON BEHALF OF SAN DIEGO GAS & ELECTRIC COMPANY IN SUPPORT OF SECOND AMENDED APPLICATION

CHAPTER 6

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

February 9, 2016

#301914

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PREPARED DIRECT TESTIMONY OF

WILLIAM G. SAXE IN SUPPORT OF SECOND AMENDED APPLICATION

CHAPTER 6

I. OVERVIEW AND PURPOSE

The purpose of my direct testimony is to present San Diego Gas & Electric Company's ("SDG&E") updated marginal distribution demand and customer costs, and the resulting electric allocation of distribution revenues to customer classes based on these marginal distribution costs.

My testimony is organized as follows:

- **Section II – Background**: describes the development of the proposed marginal distribution demand and customer costs, and the use of these marginal costs to develop the proposed electric distribution revenue allocation;
- **Section III – Marginal Distribution Demand Costs**: presents the development of the proposed updated marginal distribution demand costs based on the National Economic Research Associates ("NERA") Regression Method;
- **Section IV – Marginal Distribution Customer Costs**: presents the development of the proposed updated marginal distribution customer costs based on the Rental Method;
- **Section V – Distribution Revenue Allocation**: presents the proposal to use the updated marginal costs coupled with the Equal Percent of Marginal Costs ("EPMC") method to allocate the authorized distribution revenue requirement;
- **Section VI – Summary and Conclusion**: provides a summary of recommendations; and
- **Section VII – Statement of Qualifications**: presents my qualifications.

My testimony also contains the following:

- **Appendix – Glossary of Acronyms;**
- **Attachment A – Marginal Distribution Costs;**
- **Attachment B – Distribution Revenue Allocation;**
- **Attachment C – Customer Service Distribution Cost Allocation;**
- **Attachment D – Revisions to 2016 Marginal Distribution Customer Costs and Distribution Revenue Allocation; and**
- **Attachment E - Illustrative New Customer Only ("NCO") Marginal Distribution Customer Costs.**

II. BACKGROUND

For more than 30 years, the California Public Utilities Commission ("Commission") has relied on marginal costs as the basis for revenue allocation and rate design development for the different customer classes. My testimony presents SDG&E's updated studies for both marginal distribution demand and customer costs. The marginal distribution demand costs are based on the NERA Regression Method while the marginal distribution customer costs utilize the Rental Method. Because recent SDG&E rate design proceedings, specifically its Test Year ("TY") 2008 and TY 2012 General Rate Case ("GRC") Phase 2 proceedings (Application ("A.") 07-01-047 and A.11-10-002, respectively), were decided by settlement on revenue allocation, there was no formal adoption of marginal costs or marginal cost methodology in those proceedings.

Marginal cost is the change in costs caused by providing one additional unit of a good or service. In the electric utility context, marginal cost is defined as the change in costs to provide electric service to customers. Marginal distribution demand costs measure the cost of serving an additional unit of customer kilowatt ("kW") demand on the electric distribution grid while marginal distribution customer costs reflect the cost of adding an additional customer to the electric distribution grid. These marginal distribution costs are used as a reference for the determination of cost-based rates when SDG&E designs distribution rates to reflect the costs of providing utility service.

SDG&E is proposing that the updated marginal distribution costs proposed in this TY 2016 GRC Phase 2 Application provide the basis for the updated allocation of authorized distribution revenue requirements to customer classes.

III. MARGINAL DISTRIBUTION DEMAND COSTS

A. Marginal Distribution Demand Cost Background

Marginal distribution demand costs represent the cost of providing facilities from the high side of the substation to the final line transformer in order to meet the customer's individual demands. These marginal distribution demand costs are separated into feeder and local distribution components and substation components for the purposes of this GRC Phase 2 Application.

The development of marginal distribution demand costs focuses solely on distribution costs related to load growth. Therefore these marginal distribution demand costs do not include distribution costs related to reliability investments, replacement costs, or customer access costs, because these costs are not considered load growth-related.

The distribution demand cost component is derived in units of dollars-per-kW. To more accurately reflect the true investment cost, the costs are adjusted by various loading factors. These loading factors reflect additional costs that are necessary to meet the needs related to the addition of capacity to the distribution grid. Loading factors have been derived for Operations &

Maintenance (“O&M”), Administrative & General (“A&G”), General Plant (“GP”), and Working Capital (“WC”).

B. Marginal Feeder and Local Distribution Cost

Marginal feeder and local distribution costs represent the cost of expanding facilities from the distribution substation to the point of customer access to serve an additional kW of demand. The cost of feeder and local distribution facilities is based on the projected investments needed to meet load growth on the SDG&E distribution grid during a specific planning horizon. These facilities include poles, fixtures, capacitors, and overhead and underground conductors and devices.

SDG&E will continue the use of the NERA Regression Method to calculate marginal feeder and local distribution costs. By definition, the NERA Regression Method uses ten years of historical and five years of forecasted feeder and local distribution investments along with annual distribution system peak loads in a regression methodology. The NERA Regression Method identifies the utility’s cumulative incremental changes in distribution system peak loads as the independent variable, the utility’s cumulative incremental distribution growth-related investments as the dependent variable, and then regresses the data over a fifteen-year period of data points, years 2002-2016 in this proceeding.

The feeder and local distribution investments used in the NERA Regression Method were obtained from distribution capital budget forecasts for the period 2014 through 2016.[1] Only three years of forecasted data was available from the capital budget data. Since only three years of forecast data was available, twelve years of historical investment data from years 2002 through 2013 was used to get fifteen years of data points for the NERA Regression Method.

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[1] 2014-2016 Distribution Capital Budget Forecasts are found in the SDG&E TY 2016 GRC Phase 1 (A.14-11-003), Direct Testimony of John D. Jenkins, Exhibit SDG&E-09, Appendix A.

Because marginal feeder and local distribution costs reflect the cost to meet new demand on the distribution grid, only capital budget investments and historical investments related to capacity additions were used in the regression calculation.

After obtaining the feeder and local distribution investment using the NERA Regression Method, the result is then adjusted to reflect both GP and WC loaders. The resulting amount (reflected in $/kW) is then annualized to $/kW-year using a Real Economic Carrying Charge ("RECC") factor derived for feeder and local distribution plant accounts. The annualized investment amount then receives an A&G plant loader, fixed O&M loader, and A&G fixed O&M loader. Lastly, the resulting loaded annualized investment sum is escalated to 2016 dollars to derive the marginal distribution demand costs for feeder and local distribution.[2]

SDG&E's marginal distribution demand costs for feeder and local distribution are provided in Attachment A.

C. Marginal Substation Costs

Marginal substation costs represent the forecasted cost for construction of substations to serve an additional kW of demand. The cost of substations is based on the projected investments needed to meet the load growth on the SDG&E distribution grid during a given period of time.

SDG&E will continue the use of the NERA Regression Method to calculate marginal substation costs. Again, by definition the NERA Regression Method uses ten years of historical and five years of forecast substation investments along with annual distribution system peak loads. The NERA Regression Method identifies the utility's cumulative incremental changes in distribution system peak loads as the independent variable, the utility's cumulative incremental

[2] 2016 escalations are the cost escalation factors presented in SDG&E TY 2016 GRC Phase 1 (A.14-11-003), Direct Testimony of Scott R. Wilder, Exhibit SDG&E-33, Workpapers.

distribution growth-related substation investments as the dependent variable, and then regresses the data over a fifteen-year period of data points, years 2002-2016 in this proceeding.

The substation investments used to calculate marginal substation costs were obtained from capital budget forecasts for the period 2014 through 2016.[3] Only three years of forecasted substation data was available from the capital budget data. Because only three years of forecast data was available, twelve years of historical investment data from years 2002 through 2013 was used to get fifteen years of data points for the NERA Regression Method. Because these marginal costs reflect the incremental substation costs needed to meet new demand on the distribution grid, only capital budget investments and historical investments related to capacity additions were used in the regression calculation. After obtaining the substation investment using the NERA Regression Method, the result is then adjusted to reflect both GP and WC loaders. The resulting amount (reflected in $/kW) is then annualized to $/kW-year using a RECC factor derived for substation plant accounts. The annualized investment then receives an A&G plant loader, fixed O&M loader, and A&G fixed O&M loader. Lastly, the resulting loaded annualized investment sum is escalated to 2016 dollars to derive the marginal distribution demand costs for substations.

SDG&E's marginal distribution costs for substations are provided in Attachment A.

IV. MARGINAL DISTRIBUTION CUSTOMER COSTS

A. Marginal Distribution Customer Cost Background

Marginal distribution customer costs represent the cost of providing an individual customer access to electrical service. These marginal costs are composed of two types of costs. The first is the cost associated with the investment required to provide access (hook up) to a new

[3] 2014-2016 Distribution Capital Budget Forecasts presented in the SDG&E TY 2016 GRC Phase 1 (A.14-11-003), Direct Testimony of John D. Jenkins, Exhibit SDG&E-09, Appendix A.

customer. The second relates to the ongoing costs of maintaining the new customer. These two kinds of costs vary by customer type, size, service voltage, and type of equipment used for access. Examples of the above costs include distribution-related investments for items such as transformers, service runs, meters, customer related O&M, Customer Service Distribution, A&G, GP and WC.

The marginal distribution customer cost methodology presented by SDG&E in prior electric marginal cost proceedings has been based on the Rental Method, as opposed to the "New Customer Only" ("NCO") Method that some parties have proposed in the past. In this proceeding, SDG&E will continue the use of the Rental Method to calculate unit marginal customer costs for the various customer classes, because it sends a more accurate and more reasonable price signal on the cost of providing an individual customer access to the electrical system. In the practical application of customer electricity rates, all customers pay a "rental" cost for the distribution customer-related equipment and other services necessary to maintain an account. The Rental Method follows the same process by applying the annualized investment cost and ongoing costs required to maintain the accounts of all customers. Conversely, the NCO Method understates the marginal distribution customer costs because this method takes the full cost per customer to hook up a new customer (not the annualized cost), multiplies that value only by the number of new customers estimated to be added in that class, and then divides this amount by the total number of customers in the class to get the unit cost per customer. This results in inefficient price signals to customers considering new hookups because the approach assures that new customers will never pay the full costs incurred to hook up to the utility's electric system. For this reason, the Rental Method is the better method to use to develop the marginal distribution customer costs in this proceeding.

SDG&E's updated marginal distribution customer costs are provided in Attachment A and consist of Transformer, Service and Meter ("TSM"), O&M, and Customer Service Distribution costs, as described below. Attachment D describes the changes in the development of the TSM costs used to calculate the updated marginal distribution customer costs presented in Attachment A compared to the updated marginal distribution customer costs filed in SDG&E's 2016 GRC Phase 2 (A.15-04-012) in April 2015.

In addition, as requested by the Administrative Law Judge's rulings made at the January 26, 2016 Pre-Hearing Conference in this proceeding (A.15-04-012), Attachment E presents the calculation of the marginal distribution customer costs based on the NCO Method that has been used by other parties in SDG&E's previous GRC Phase 2 proceedings, including the NCO Method assumptions used in those proceedings. These illustrative NCO Method marginal distribution customer costs are presented for comparison purposes only and are not being proposed by SDG&E for the reasons stated above.

B. Transformer, Service and Meter ("TSM") Costs

The customer investment costs for each customer type, customer size, and service voltage level were calculated using the TSM method. The TSM method includes transformers, services, and meters as the basis of the customer hookup costs. The installed costs for the TSM component are based on a detailed analysis of each individual component. Cost estimates for the various customer demand and service levels were developed for: 1) transformers based on transformer size and the average number of customers per transformer; 2) services based on wire size, number of runs, average service length, and compression lug wires; and 3) meters based on size and type (single- or three-phase). The TSM investment cost for each customer group was based on engineering estimates for a typical customer by size and class.

To determine the average TSM costs for each customer class, customers are grouped by maximum annual demand levels (in kW). Once grouped, the TSM costs for each customer demand level are calculated by multiplying the number of customers per demand level by the estimated demand-specific cost for each TSM component. A weighted average is then calculated for each TSM component that produces the average TSM cost per customer class.

Once developed, the TSM costs are multiplied by GP and WC loading factors. After receiving GP and WC loaders, the TSM costs are then converted to an annualized amount (dollars-per-customer-per-year) by using a RECC that calculates an annual economic rent.

C. Operations & Maintenance ("O&M") Costs

In order to develop a per-customer O&M cost allocation, SDG&E analyzed the 2013 Federal Energy Regulatory Commission ("FERC") Form 1 Distribution O&M account costs (FERC Accounts 580-598) to determine which portion of each account relates to distribution demand and which relates to customer connection. The customer-connection-related account amounts are totaled for the O&M costs.

SDG&E then allocates the customer-related O&M costs to the various rate schedules by using a factor derived from each schedule's percentage of the grand total of the estimated TSM cost. These amounts are then adjusted by an A&G factor before calculating the per-customer O&M cost.

D. Customer Service Distribution Costs

Customer Service Distribution Costs represent costs for such activities as customer service field, advanced metering, billing, credit & collections, branch office, customer contact center, residential customer services, commercial & industrial services, communications, and customer programs. The Customer Service Distribution Costs allocated for marginal distribution customer cost purposes in this proceeding reflect the 2013 Adjusted-Recorded costs identified in SDG&E's TY 2016 GRC Application.[4]

In accordance with the 2012 TY GRC Phase 2 Partial Settlement Agreement adopted by Decision ("D.") 14-01-002,[5] SDG&E conducted an internal study of historical SDG&E Customer Service Costs to determine the appropriate allocation of each type of costs for marginal distribution cost purposes. The results of the Customer Service Cost study are provided in Attachment C.

V. DISTRIBUTION REVENUE ALLOCATION

A. Distribution Revenue Allocation Background

SDG&E proposes to use the EPMC revenue allocation method as the basis to allocate the authorized distribution revenue requirement to customer classes. The EPMC method scales the customer class distribution marginal cost revenue responsibilities up or down by a single factor to ensure that the sum equals the authorized distribution revenue requirement.

Under SDG&E's distribution revenue allocation proposal, the authorized distribution revenue requirement, minus any revenues that are directly assigned to the particular customer classes,[6] is allocated among the customer classes based on the proposed marginal distribution cost revenue responsibilities by customer class. The customer class marginal costs revenue responsibilities for the distribution function is the sum of marginal customer, feeder and local distribution, and substation distribution costs. The unit marginal costs of distribution are multiplied by the appropriate cost drivers to develop the marginal distribution revenue

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[4] Adjusted 2013 Customer Services Distribution Expenses presented in the SDG&E TY 2016 GRC Phase 1 (A.14-11-003) Direct Testimony of Khai Nguyen, Exhibit SDG&E-36, p. KN-A-31, Table KN-30.
[5] SDG&E TY 2012 GRC Phase 2 (A.11-10-002) October 4, 2012 Partial Settlement Agreement, Section 3.A – Marginal Costs, p. 4.
[6] SDG&E's directly assigned distribution revenues are labeled Non-Marginal Revenue Requirement Components and identified in Attachment B.2.

allocations by customer class. Marginal customer cost revenues by customer class are developed by multiplying each class' unit marginal customer cost ($/customer/year) by the forecasted number of customers in that class. Total marginal feeder and local distribution cost revenues are developed by multiplying the unit marginal feeder and local distribution costs ($/kW/year) by the system non-coincident demand and the applicable loss factors. The customer class allocation of the marginal feeder and local distribution cost revenues is developed by multiplying the customer class' annual non-coincident demand, the applicable loss factors and the calculated ratio of the average class contribution to the peak demand at the circuit level (Effective Demand Factor or "EDF"). Total marginal substation cost revenues are developed by multiplying the unit marginal substation costs ($/kW/year) by the system non-coincident demand and the applicable loss factors. The customer class allocation of the marginal substation cost revenues is developed by multiplying the customer class' annual non-coincident demand, the applicable loss factors and the EDF at the substation level.

The sum of the marginal customer, feeder and local distribution, and substation distribution cost revenues is used to develop the distribution EPMC allocation factor. The EPMC allocation factor is then used to scale the marginal distribution class revenue allocations to equal the authorized distribution revenue requirement. The distribution revenue allocation by customer class is provided in Attachment B. Attachment B.1 presents the distribution marginal cost allocation factors by customer class. Attachment B.2 presents the allocation of distribution revenues to each customer class based on the distribution marginal cost allocations factors. Attachment B.3 presents the resulting distribution EPMC rates and revenues by customer class. Attachment D describes the changes to the calculation of the distribution revenue allocation presented in Attachment B compared to the updated marginal distribution revenue allocation filed in SDG&E's 2016 GRC Phase 2 (A.15-04-012) in April 2015.

B. Correction to Implementation of Method used for Distribution Revenue Allocation

In SDG&E's previous GRC Phase 2 proceeding (TY 2012 GRC Phase 2, A.11-10-002), SDG&E performed a study to determine the customer class' contribution to circuit and substation peak demands ("Circuit and Substation Study Requirement"), in compliance with D.08-02-034.[7] The Circuit and Substation Study Requirement stated the following:

> "An analysis, with affirmative testimony supporting the appropriate level of demand distribution billing determinants by class and the method of calculating those billing determinants for 1) substations, 2) feeders, and 3) new business (if included in demand, recognizing that the Farm Bureau also wants to analyze it as part of the customer hookup). Without prescribing the specifics of the study, the discussion at pages 10-11 and Attachment A of the Barkovich/Yap rebuttal testimony, PG&E's use of Peak Capacity Allocation Factors (PCAF), and the actual timing of substation demands should be considered. SDG&E should develop data to provide ten years of historical data for distribution and customer-related investment."[8]

SDG&E's TY 2012 GRC Phase 2 direct testimony addressed its compliance with the Circuit and Substation Study Requirement, including its proposal to incorporate the results of this study in the allocation of distribution revenues.[9] The study found each customer class' contribution to circuit and substation peaks based on 2008 load research data, developed the class EDFs based on dividing the class' load at the time of the circuit and substation peaks by the class' non-coincident demand based on the 2008 load research data, and then calculated an averaged class EDF by averaging the EDFs by customer class.

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[7] D.08-02-034 adopted study requirements listed in Attachment A to SDG&E's Motion for Adoption of All Party and All Issue Settlement in SDG&E's TY 2008 GRC Phase 2 (A.07-01-047), including Compliance Requirement 6 requiring a study on class contribution to circuit and substation demands.
[8] SDG&E TY 2012 GRC Phase 2, A.11-10-002, Second Revised Prepared Direct Testimony of Cynthia Fang, Chapter 2, Attachment I – 2008 GRC Phase 2 Study Requirements, p. 11.
[9] SDG&E TY 2012 GRC Phase 2, A.11-10-002, Second Revised Prepared Direct Testimony of Cynthia Fang, Chapter 2, Attachment I – 2008 GRC Phase 2 Study Requirements, pp. 11 and 12.

In my direct testimony in the TY 2012 GRC Phase 2 proceeding, I proposed that marginal distribution demand-related costs be allocated to customer classes based on the estimated class' loads at the time of circuit and substation peaks.[10] The circuit and substation loads used were the class' loads coincident with circuit and substation peak loads based on the 2008 load research data identified in the Circuit and Substation Study Requirement results. For this reason, the allocation of distribution demand-related cost revenues proposed by SDG&E in the TY 2012 GRC Phase 2 proceeding, which provided one of the reference points for the settlement related to distribution revenue allocation agreed to by settling parties and adopted by D.14-01-002,[11] were based on the class' percentage of circuit and substation peak demands (i.e., estimated 2008 class' demand coincident with the time of the circuit and substation peaks divided by the total 2008 circuit and substation peak demands, respectively) multiplied by the TY 2012 forecasted system non-coincident demand determinants.

In developing the distribution revenue allocation proposal in this TY 2016 GRC Phase 2 proceeding, SDG&E realized that it had incorrectly applied the results of the Circuit and Substation Study Requirement in the allocation of the marginal distribution demand-related costs in the TY 2012 GRC Phase 2 proceeding. Although SDG&E incorporated the results from the Circuit and Substation Study Requirement in the allocation of distribution revenues, it inadvertently used the class' coincident peak demands based on the 2008 load research data from the study rather than using the average class EDFs developed in the study. Using the average class EDF multiplied by the class' TY 2012 forecasted non-coincident demand determinants to

[10] SDG&E TY 2012 GRC Phase 2 (A.11-10-002), Second Revised Prepared Direct Testimony of William G. Saxe, Chapter 3, p. WGS-3, lines 16-18.

[11] TY 2012 GRC Phase 2 (A.11-10-002), October 4, 2012, Partial Settlement Agreement, Section 3.B – Revenue Allocation, pp. 4-8.

allocate marginal distribution demand-related cost revenues in the TY 2012 GRC Phase 2 proceeding would have correctly captured the class' contribution to circuit and substation peaks based on class load diversity identified in the TY 2012 forecasted non-coincident demand determinants. The use of coincident peak demands based on the 2008 load research data from the Circuit and Substation Study Requirement to allocate marginal distribution demand-related revenues understated the responsibility of the residential class for these marginal distribution demand-related cost revenues and overstated the responsibility of the non-residential classes for these marginal distribution demand-related cost revenues that was presented in my TY 2012 GRC Phase 2 rebuttal testimony.[12] The correction to the implementation method used to allocate marginal distribution demand-related cost revenues to customer classes, that is the application of the class' EDFs rather than the application of the class' coincident peak demands in the TY 2016 GRC Phase 2 proceeding, appropriately bases the allocation on the class' average EDF multiplied by their TY 2016 forecasted non-coincident demand determinants. It should be noted that SDG&E's current electric rates, which reflect the implementation of D.14-01-002 adopting the partial settlement agreement on revenue allocation in SDG&E's TY 2012 GRC Phase 2 proceeding, correctly comport with the approved settlement.

VI. SUMMARY AND CONCLUSION

For the foregoing reasons, the updated marginal distribution demand and customer costs, as presented in Attachment A, as well as its proposal to use these marginal costs coupled with the EPMC method to allocate authorized distribution revenue requirements to customer classes, as presented in Attachment B, are reasonable and should be adopted by the Commission.

This concludes my prepared direct testimony.

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[12] See, SDG&E TY 2012 GRC Phase 2, A.11-10-002, Prepared Rebuttal Testimony of William G. Saxe, Chapter 3, Attachment A.

VII. STATEMENT OF QUALIFICATIONS

My name is William G. Saxe. My business address is 8330 Century Park Court, San Diego, California 92123. I am employed as Project Manager III in the Customer Pricing Department of SDG&E. I have worked for SDG&E since February 2001. Prior to joining SDG&E, I was employed by Sempra Energy, the parent company of SDG&E, from April 1999 through January 2001. In addition, I was employed by the Illinois Commerce Commission ("ICC") from September 1990 through April 1999.

I received a Bachelor of Science degree in Economics from the University of Wisconsin-Madison in 1985. I received a Master of Business Administration degree, with a concentration in Finance, from the University of Wisconsin-Madison in 1990.

I have previously testified before this Commission on rate design, marginal cost and other issues. In addition, I have previously submitted testimony before the FERC and the ICC.

#301914

APPENDIX – GLOSSARY OF ACRONYMS

A&G	Administrative & General
Commission	California Public Utilities Commission
EDF	Effective Demand Factor
EPMC	Equal Percent of Marginal Costs
FERC	Federal Energy Regulatory Commission
GP	General Plant
GRC	General Rate Case
ICC	Illinois Commerce Commission
kW	Kilowatt
NCO	New Customer Only
NERA	National Economic Research Associates
O&M	Operations & Maintenance
RECC	Real Economic Carrying Charge
SDG&E	San Diego Gas & Electric Company
TSM	Transformer, Service and Meter
TY	Test Year
WC	Working Capital

ATTACHMENT A

MARGINAL DISTRIBUTION COSTS

ATTACHMENT A

SAN DIEGO GAS & ELECTRIC COMPANY ("SDG&E")
TEST YEAR ("TY") 2016 GENERAL RATE CASE ("GRC") PHASE 2, APPLICATION ("A.") 15-04-012
MARGINAL DISTRIBUTION COSTS

Proposed Distribution Marginal Unit Cost by Customer Class

Line No.	Description (A)		Secondary (B)	Primary (C)	Transmission (D)	Line No.
1	Customer Marginal Cost Based on Rental Method ($/Customer/Year):					1
2	Residential		$152.61			2
3	Small Commercial					3
4		0 - 5 kW	$327.81	$832.16		4
5		>5 - 20 kW	$600.92	$832.16		5
6		>20 - 50 kW	$1,267.71	$832.16		6
7		>50 kW	$1,766.15	$1,776.44		7
8		Average	$530.95	$967.06		8
9						9
10	Medium/Large Commercial & Industrial					10
11		≤500 kW	$2,351.56	$1,145.02	$8,131.77	11
12		500 - 12 MW	$5,718.65	$1,340.52	$14,356.92	12
13		> 12 MW		$2,080.23	$20,928.27	13
14		Average	$2,426.30	$1,244.41	$11,462.83	14
15						15
16	Agricultural					16
17		≤20 kW	$594.09	$966.08		17
18		>20 kW	$2,185.46	$1,115.35		18
19		Average	$1,019.73	$1,108.25		19
20						20
21	Lighting ($/Lamp/Year)		$12.95			21
22						22
23						23
24	Demand-Related Marginal Cost:					24
25	Feeders & Local Distribution Demand ($/kW/Year)		$77.97	$77.97		25
26						26
27	Substation Demand ($/kW/Year)		$22.05	$22.05		27
28						28
29	Total Demand-Related Marginal Cost ($/kW/Year)		$100.02	$100.02		29

Note: **Distribution Marginal Unit Cost by Customer Class**: the distribution marginal unit costs by customer class presented are from the Chapter 6 workpapers.

ATTACHMENT B

DISTRIBUTION REVENUE ALLOCATION

ATTACHMENT B.1

SAN DIEGO GAS & ELECTRIC COMPANY ("SDG&E")
TEST YEAR ("TY") 2016 GENERAL RATE CASE ("GRC") PHASE 2, APPLICATION ("A.") 15-04-012
DISTRIBUTION REVENUE ALLOCATION

Distribution Marginal Cost Allocation Factor by Customer Class

Line No.	Customer Class (A)	Customer Marginal Cost Revenue ($000) (B)	Percentage Allocation (%) (C)	Demand-Related Marginal Cost Revenue ($000) (D)	Percentage Allocation (%) (E)	Total Distribution Marginal Cost Revenue ($000) (F)	Distribution Marginal Cost Allocation Factor (%) (G)	Line No.
1	Residential	$196,406	60.17%	$395,045	52.35%	$591,451	54.71%	1
2								2
3	Small Commercial	$65,519	20.07%	$91,333	12.10%	$156,852	14.51%	3
4								4
5	Medium/Large Commercial & Industrial	$58,991	18.07%	$259,014	34.32%	$318,005	29.42%	5
6								6
7	Agricultural	$3,467	1.06%	$8,016	1.06%	$11,482	1.06%	7
8								8
9	Lighting	$2,055	0.63%	$1,242	0.16%	$3,297	0.30%	9
10								10
11	System	$326,437	100.00%	$754,650	100.00%	$1,081,087	100.00%	11

Note:

(1) **Distribution Marginal Cost Allocation Factors by Customer Class**: the distribution marginal cost allocation factor by customer class presented are from the Chapter 6 Workpapers.
(2) **Customer Marginal Cost Revenue**: reflects customer-related distribution marginal costs.
(3) **Demand-Related Marginal Cost Revenue**: reflects feeder & local distribution and substation demand-related distribution marginal costs.

ATTACHMENT B.2

SAN DIEGO GAS & ELECTRIC COMPANY ("SDG&E")
TEST YEAR ("TY") 2016 GENERAL RATE CASE ("GRC") PHASE 2, APPLICATION ("A.") 15-04-012
DISTRIBUTION REVENUE ALLOCATION

Distribution Revenue Allocation by Customer Class

Line No.	Customer Class (A)	Updated Distribution Revenue Allocation: Distribution Allocation Factors (%) (B)	Updated Distribution Revenue Allocation: Non Marginal Distribution Revenue ($000) (C)	Updated Distribution Revenue Allocation: Marginal Distribution Revenue ($000) (D)	Updated Distribution Revenue Allocation: Total Distribution Revenue Allocation ($000) (E)	Current Total Distribution Revenue Allocation ($000) (F)	Percentage Change (%) (G)	Line No.
1	**Residential**	54.71%		$772,652	$772,652	$678,801	13.83%	1
2								2
3	**Small Commercial**	14.51%		$204,906	$204,906	$180,828	13.32%	3
4								4
5	**Medium/Large Commercial & Industrial**	29.42%	$8,509	$415,431	$423,940	$537,227	-21.09%	5
6								6
7	**Agricultural**	1.06%		$15,000	$15,000	$19,030	-21.18%	7
8								8
9	**Lighting**	0.30%	$4,912	$4,307	$9,219	$9,831	-6.22%	9
10								10
11	**System**	100.00%	$13,421	$1,412,296	$1,425,717	$1,425,717	0.00%	11
12								12
13	Distribution Revenue Requirement ($000):	$1,425,717						13
14								14
15	Non Marginal Revenue Requirement Components ($000):							15
16	Lighting Facilities Charge Revenues:	$4,912						16
17	Standby Revenues:	$5,579						17
18	Distance Adjustment Fee Revenues:	$2,930						18

Note:

(1) **Distribution Revenue Allocation by Customer Class**: the distribution revenue allocation by customer class presented are from the Chapter 6 Workpapers.
(2) **Updated Distribution Revenue Allocation**: allocation of the current distribution revenue requirement based on the marginal Distribution Allocation Factors presented in this Application.
(3) **Current Total Distribution Revenue Allocation**: allocation of current distribution revenue requirement based on the current class distribution allocation percentages reflected in current rates; rates . effective November 1, 2015, pursuant to SDG&E Advice Letter 2791-E.
(4) **Distribution Revenue Requirement**: the $1,425,717,000 Distribution Revenue Requirement reflects the current distribution revenues being collected in rates effective November 1, 2015, excluding revenues that have separate allocation treatment such as Self Generation Incentive Program ("SGIP"), Demand Response ("DR"), and Customer Service Initiative ("CSI") costs.
(5) **Non-Marginal Lighting Facilities Charge Revenues**: Lighting Facilities Charges of $4,912,000 are the annual lighting facilities revenues identified in the Lighting Model from SDG&E witness Christopher Swartz (Chapter 2) workpapers.
(6) **Non-Marginal Standby Revenues**: Standby Revenues of $5,579,000 are the standby revenues based on the forecasted standby determinants multiplied by the applicable current standby rates effective November 1, 2015, pursuant to SDG&E Advice Letter 2791-E.
(7) **Non-Marginal Distance Adjustment Fee Revenues**: Distance Adjustment Fees of $2,930,000 are the annual distance adjustment fees revenues based on the forecasted overhead and underground distance adjustment fee determinants in feet multiplied by the applicable current distance adjustment fees effective November 1, 2015, pursuant to SDG&E Advice Letter 2791-E.

ATTACHMENT B.3

SAN DIEGO GAS & ELECTRIC COMPANY ("SDG&E")
TEST YEAR ("TY") 2016 GENERAL RATE CASE ("GRC") PHASE 2, APPLICATION ("A.") 15-04-012
DISTRIBUTION REVENUE ALLOCATION

Distribution Equal Percentage of Marginal Cost ("EPMC") Rates and Revenue by Customer Class

Line No.	Customer Class (A)		Marginal Distribution Rate (B)	EPMC Distribution Rate (C)	EPMC Distribution Revenue Allocation ($000) (D)	Line No.
1	Residential					1
2		Customer Marginal Cost ($/Customer-Month)	$12.72	$16.61		2
3		Demand-Related Marginal Cost ($/Non-Coincident kW)	$8.06	$10.53		3
4		Total - Residential			$772,652	4
5						5
6	Small Commercial					6
7		Customer Marginal Cost ($/Customer-Month)				7
8		Secondary				8
9		0 - 5 kW	$27.32	$35.69		9
10		>5 - 20 kW	$50.08	$65.42		10
11		>20 - 50 kW	$105.64	$138.01		11
12		>50 kW	$147.18	$192.27		12
13		Secondary Total	$43.88	$57.32		13
14						14
15		Primary				15
16		0 - 5 kW	$69.35	$90.59		16
17		>5 - 20 kW	$69.35	$90.59		17
18		>20 - 50 kW	$69.35	$90.59		18
19		>50 kW	$148.04	$193.39		19
20		Primary Total	$70.41	$91.98		20
21						21
22		Demand-Related Marginal Cost ($/Non-Coincident kW)				22
23		Secondary	$9.55	$12.47		23
24		Primary	$9.50	$12.41		24
25		Total	$9.55	$12.47		25
26						26
27		Total - Small Commercial			$204,906	27
28						28
29	Medium/Large Commercial & Industrial					29
30						30
31		Secondary				31
32		≤500 kW	$195.96	$256.00		32
33		500 - 12 MW	$476.55	$622.55		33
34		Secondary Total	$202.51	$264.55		34
35						35
36		Primary				36
37		≤500 kW	$95.42	$124.65		37
38		500 - 12 MW	$111.71	$145.93		38
39		> 12 MW	$173.35	$226.46		39
40		Primary Total	$105.00	$137.17		40
41						41
42		Transmission				42
43		≤500 kW	$677.65	$885.26		43
44		500 - 12 MW	$1,196.41	$1,562.95		44
45		> 12 MW	$1,744.02	$2,278.33		45
46		Transmission Total	$1,031.47	$1,347.48		46
47						47
48		Demand-Related Marginal Cost ($/Non-Coincident kW)				48
49		Secondary	$10.45	$13.65		49
50		Primary	$10.39	$13.57		50
51		Total	$10.43	$13.63		51
52						52
53		Total - Medium/Large Commercial & Industrial			$415,431	53

SAN DIEGO GAS & ELECTRIC COMPANY ("SDG&E")
TEST YEAR ("TY") 2016 GENERAL RATE CASE ("GRC") PHASE 2, APPLICATION ("A.") 15-04-012
DISTRIBUTION REVENUE ALLOCATION

Distribution Equal Percentage of Marginal Cost ("EPMC") Rates and Revenue by Customer Class

Line No.	Customer Class (A)	Marginal Distribution Rate (B)	EPMC Distribution Rate (C)	EPMC Distribution Revenue Allocation ($000) (D)	Line No.
54					54
55	Agricultural				55
56	Customer Marginal Cost ($/Customer-Month)				56
57	Secondary				57
58	≤20 kW	$49.51	$64.68		58
59	>20 kW	$182.12	$237.92		59
60	Secondary Total	$73.69	$96.27		60
61					61
62	Primary				62
63	≤20 kW	$80.51	$105.17		63
64	>20 kW	$92.95	$121.42		64
65	Primary Total	$84.70	$110.65		65
66					66
67	Demand-Related Marginal Cost ($/Non-Coincident kW)				67
68	Secondary	$5.25	$6.86		68
69	Primary	$5.23	$6.83		69
70	Total	$5.25	$6.86		70
71					71
72	Total - Agricultural			$15,000	72
73					73
74	Lighting				74
75	Customer Marginal Cost ($/kWh)	$1.08	$1.41		75
76	Demand-Related Marginal Cost ($/kWh)	$4.86	$6.35		76
77	Total - Lighting			$4,307	77
78					78
79	Total-System				79
80	Customer Marginal Cost ($/Customer-Month)			$426,447	80
81	Demand-Related Marginal Cost ($/Non-Coincident kW)			$985,849	81
82	Total - System			$1,412,296	82

GRC Phase 1 Distribution Revenue Requirement	1,425,717
Non-Marginal Revenue Requiremen	13,421
Marginal Distribution Revenue Requirement Allocatioı	1,412,296
Marginal Customer Distribution Revenue Requiremen	326,437
Marginal Demand-Related Distribution Revenue Requiremen	754,650
Total Marginal Distribution Revenue Requiremen	1,081,087
EPMC Allocation Factor	130.64%

Notes:

(1) **Distribution EPMC Rates and Revenues by Customer Class**: the distribution EPMC rates and revenues by customer class presented are from the Chapter 6 Workpapers.
(2) **Marginal Distribution Rate**: equals the marginal cost by class and by voltage level for demand-related margin cost divided by the class determinants.
(3) **EPMC Distribution Rate**: equals the Marginal Distribution Rate multiplied by the EPMC Distribution Allocation Factor.
(4) **EPMC Distribution Revenue Allocation**: equals the EPMC Distribution Rate multiplying by the applicable determinants.

ATTACHMENT C

CUSTOMER SERVICE COST ALLOCATION

ATTACHMENT C

SAN DIEGO GAS & ELECTRIC COMPANY (“SDG&E”)
TEST YEAR (“TY”) 2016 GENERAL RATE CASE (“GRC”) PHASE 2
APPLICATION (“A.”) 15-04-012
CUSTOMER SERVICES COST STUDY

SDG&E TY 2012 GRC Phase 2 Requirement From Partial Settlement Agreement Adopted in Decision (“D.”) 14-01-002

Background: the SDG&E TY 2012 GRC Phase 2 (A.11-10-002) Partial Settlement Agreement adopted in D.14-01-002 requires SDG&E to perform a study to determine the appropriate allocation of customer account and service costs by customer class for use in updating its marginal distribution customer costs in its next GRC Phase 2 proceeding.[1] In SDG&E’s TY 2012 GRC Phase 2 proceeding, SDG&E allocated the customer account and service costs to customer classes based on the number of customers in each class. The purpose of the study requirement is for SDG&E to evaluate the different types of customer account and service costs to determine the most appropriate allocation of these costs for the purpose of updating marginal distribution customer costs.

In the development of marginal distribution customer costs in SDG&E’s TY 2016 GRC Phase 2 proceeding, the customer service costs used are the 2013 Adjusted-Recorded Distribution Customer Services (“Customer Services”) costs identified in SDG&E’s TY 2016 GRC Phase 1 proceeding (A.14-11-003).[2] SDG&E evaluated each cost category that make up the Customer Services costs to determine how these costs were incurred or are expected to be incurred to provide service to the various customer classes. What the study showed was that in most cases the historical Customer Services cost data only provides information to allocate the costs to Residential and Non-Residential customers without the ability to identify the costs associated with each specific Non-Residential customer class (Small Commercial, Medium/Large Commercial & Industrial (“M/L C&I”), Agricultural, and Lighting). For this reason, it was necessary in most cases to select an approach to allocate the Non-Residential portion of the Customer Services costs to Non-Residential customer classes.

Below are cost categories that make up the Customer Services costs, including the study allocation results by customer class for each cost category[3]:

Customer Service Field (“CSF”) Costs: Approximately $5.6 million in 2013 Adjusted-Recorded CSF costs. Based on average CSF job orders performed during 2011-2013, that includes job order details by customer classes, CSF costs are allocated 79.1% to Residential, 16.2% to Small Commercial, 3.7% to M/L C&I, 0.9% to Agricultural, and 0.1% to Lighting.

[1] October 5, 2012 Partial Settlement Agreement in SDG&E’s TY 2012 GRC Phase 2 proceeding (A.11-10-002), Section 3.A – Marginal Costs, p. 4.
[2] 2013 Adjusted-Recorded Customer Services Electric Distribution Costs identified in SDG&E TY 2016 GRC Phase 1 (A.14-10-003) Direct Testimony of Khai Nguyen, Exhibit SDG&E-36, p. KN-A-31, Table KN-30.
[3] Please note that the percentages identified for each Customer Services cost category may not add up to 100% because of rounding.

Advanced Metering Operations ("AMO") Costs: Approximately $7.6 million in 2013 Adjusted-Recorded AMO costs. Based on estimated AMO work orders, that includes work order details by customer classes, AMO costs are allocated 27.4% to Residential, 28.9% to Small Commercial, 38.7% to M/L C&I, 4.9% to Agricultural, and 0.1% to Lighting.

Billing Costs: Approximately $3.3 million in 2013 Adjusted-Recorded Billing costs. Based on average billing work done in 2011-2013, the allocations of the Billing costs are allocated 65.3% to Residential and 34.7% to Non-Residential customers. Because the historical Billing data does not include details to determine how much of the 34.7% is associated with each Non-Residential customer class, the Non-Residential customer classes were allocated their portion of the 34.7% Billing Costs based on each class' percentage of average 2011-2013 annual non-residential customers. The resulting allocation is 65.3% to Residential, 27.3% to Small Commercial, 5.2% to M/L C&I, 0.9% to Agricultural, and 1.3% to Lighting.

Credit & Collections Costs: Approximately $1.8 million in 2013 Adjusted-Recorded Credit & Collection costs. Based on average Credit & Collections payment and collection services performed during 2011-2013, the allocations of the Credit & Collection costs are allocated 89.8% to Residential and 10.2% to Non-Residential customers. Because the historical Credit & Collections data does not include details to determine how much of the 10.2% is associated with each Non-Residential customer class, the Non-Residential customer classes were allocated their portion of the 10.2% Credit & Collection costs based on each class' percentage of average 2011-2013 annual non-residential customers. The resulting allocation is 89.8% to Residential, 8.0% to Small Commercial, 1.5% to M/L C&I, 0.3% to Agricultural, and 0.4% to Lighting.

Remittance Processing & Postage Costs: Approximately $3.4 million in 2013 Adjusted-Recorded Remittance Processing & Postage costs. Because these costs are associated with customers that receive paper bills, the current number of customers receiving paper bills was pulled resulting in an allocation of 85.6% to residential and 14.4% to Non-Residential customers. Because this data does not include details on the number of paper bills by each Non-Residential customer class, the Non-Residential customer classes were allocated their portion of the 14.4% Remittance Processing & Postage costs based on each class' percentage of average 2011-2013 annual non-residential customer numbers. The resulting allocation is 85.6% to Residential, 11.3% to Small Commercial, 2.1% to M/L C&I, 0.4% to Agricultural, and 0.6% to Lighting.

Branch Offices Costs: Approximately $1.3 million in 2013 Adjusted-Recorded Branch Offices costs. Based on average Branch Office transactions performed during 2011-2013, the allocations of the Branch Office costs are allocated 94.3% to Residential and 5.7% to Non-Residential customers. Because the historical Branch Office transaction data does not include details to determine how much of the 5.7% is associated with each Non-Residential customer class, the Non-Residential customer classes were allocated their portion of the 5.7% Branch Offices costs based on each class' percentage of average 2011-2013 annual non-residential customers. The resulting allocation is 94.3% to Residential, 4.5% to Small Commercial, 0.8% to M/L C&I, 0.1% to Agricultural, and 0.2% to Lighting.

Customer Contact Center Operations and Support Costs: Approximately $6.0 million and $1.5 million in 2013 Adjusted-Recorded Customer Contact Center Operations and Support costs, respectively. Based on average Customer Contact Center calls received during 2011-2013, the Customer Contact Center costs are allocated 93.9% to Residential and 6.1% to Non-Residential customers. Because the historical Customer Contract Center call data does not include details to determine how much of the 6.1% is associated with each Non-Residential customer class, the Non-Residential customer classes were allocated their portion of the 6.1% Customer Contract Center Operations and Support costs based on each class' percentage of average 2011-2013 annual non-residential customers. The resulting allocation is 93.9% to Residential, 4.8% to Small Commercial, 0.9% to M/L C&I, 0.2% to Agricultural, and 0.2% to Lighting.

Residential Customer Services Costs: Approximately $4.7 million in 2013 Adjusted-Recorded Residential Customer Services costs. 100% of the Residential Customer Services costs should be allocated to Residential.

Commercial & Industrial ("C&I) Services Costs: Approximately $4.4 million in 2013 Adjusted-Recorded C&I Services costs. Based on an evaluation of the cost categories that make up the C&I services costs it was determined that approximately 39.1% of these costs is for the M/L C&I class, 1.3% is for the Small Commercial class, and the remaining 59.5% needs to be allocated to the Non-Residential classes based an appropriate allocation method. SDG&E proposes that the Non-Residential customer classes be allocated their portion of the 59.5% C&I costs based on the proposed distribution revenue allocation in this proceeding.[4] The resulting total allocation of C&I Services costs is 16.7% to Small Commercial, 81.3% to M/L C&I, 1.3% to Agricultural, and 0.8% to Lighting.

Communications, Research & Web Costs: Approximately $6.7 million in 2013 Adjusted-Recorded Communications, Research & Web costs. Based on a review of the cost categories it was determined that approximately $725,000 of these costs are directly assignable to Residential customers and approximately $204,000 of these costs are directly assignable to Non-Residential customers. Because details on the Communication, Research & Web costs associated with each customers class is not available, the directly assignable Non-Residential costs are allocated to the Non-Residential customer classes based on each class' percentage of average 2011-2013 annual non-residential customers. In addition, the $5.8 million in unassignable costs is allocated to all customer classes, including Residential, based on each class' percentage of average 2011-2013 annual total system customers. The resulting allocation is 87.4% to Residential, 9.9% to Small Commercial, 1.9% to M/L C&I, 0.3% to Agricultural, and 0.5% to Lighting.

Customer Programs & Projects Costs: Approximately $2.0 million in 2013 Adjusted-Recorded Customer Programs & Projects costs. Because these costs are mainly associated with demand response, SDG&E is proposing that the allocations of these costs be based on the current demand response allocation factors. The resulting allocation is 39.8% to Residential, 11.7% to Small Commercial, 47.5% to M/L C&I, 0.5% to Agricultural, and 0.5% to Lighting.

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[4] Because C&I Services costs are part of the Customer Services costs used in the development of the proposed distribution revenue allocation, the proposed distribution revenue allocation factors used to allocate the C&I Services costs are the factors prior to the inclusion of Customer Services costs.

Other Office and Shared Services Costs: Approximately $1.3 million in 2013 Adjusted-Recorded Other Office and Shared Services costs. SDG&E proposes to allocate these miscellaneous Customer Services costs based on the resulting combined allocation of the other Customer Services costs listed above. The resulting allocation is 67.9% to Residential, 13.6% to Small Commercial, 16.9% to M/L C&I, 1.2% to Agricultural, and 0.4% to Lighting.

ATTACHMENT D

REVISIONS TO 2016 MARGINAL DISTRIBUTION CUSTOMER COSTS AND DISTRIBUTION REVENUE ALLOCATION

ATTACHMENT D

CHANGES TO 2016 MARGINAL DISTRIBUTION CUSTOMER COSTS AND DISTRIBUTION REVENUE ALLOCATION FILED APRIL 2015 IN A.15-04-012

A. **Transformers, Services and Meter ("TSM") Costs:** the Chapter 6 testimony and workpapers reflect the following changes in the development of the TSM costs used to calculate updated marginal distribution customer costs in this filing compared to the TSM costs used in SDG&E's 2016 GRC Phase 2 (A.15-04-012) filed in April 2015:

(1) TSM Overhead Rates and Material, Labor and Equipment Costs ("Raw Costs"): the overhead rates and raw costs used to fully load the TSM costs were changed to reflect 3rd Quarter 2013 overhead rates and raw costs instead of the 1st Quarter 2014 overhead rates and raw costs used in the 2016 GRC Phase 2 filed in April 2015. The change to 2013 overhead rates and raw costs was done to be consistent with the year of the costs used in the development of the TSM costs which are 2013 costs. In addition, the overheads rates were updated to include the travel/yard factor which was mistakenly left out of the overhead rates used in the 2016 GRC Phase 2 (A.15-04-012) filed in April 2015. The travel/yard factor is applied to both the labor and equipment costs to reflect the cost to load the truck(s) for the job and the travel time to the job site, including the fuel costs for the truck(s).

(2) Transformer Costs: in addition to the update of the overhead rates and raw costs applied to transformer costs, the transformer costs were also updated to reflect the inclusion of transformer direct and indirect labor installation costs which were mistakenly left out of

the transformer costs used in the 2016 GRC Phase 2 (A.15-04-012) filed in April 2015. These changes result in small increases to the cost of most transformers serving customers with max demand less than or equal to 100 kW and small decreases to the cost of most transformers serving customers with max demand greater than 100 kW.

(3) Service Costs: in addition to the update of the overhead rates and raw costs applied to service costs, the service costs were also updated to reflect changes to wire costs. These changes result in decreases to secondary and transmission service costs and small increases to primary service costs.

(4) Meter Costs: in addition to the update of the overhead rates and raw costs applied to meter costs, the meter costs were also updated to include additional labor hours for the installation of current transformers on electric meter panels > 400 amps. These changes result in increases to meter costs, especially non-residential meter costs because of the increased labored hours required to install current transformers, if applicable.

B. Distribution Revenue Allocation: the Chapter 6 testimony and workpapers reflect the following changes to the calculation of the distribution revenue allocation in this proceeding compared to the distribution revenue allocation calculated in SDG&E's 2016 GRC Phase 2 (A.15-04-012) filed in April 2015:

(1) Updates to Marginal Distribution Customer Costs: as explained above, the marginal distribution customer costs have been updated to reflect changes in TSM costs. These marginal costs are used to develop the distribution revenue allocation and thus, changes

to these costs result in changes to the proposed distribution revenue allocation, presented in Attachment B. The changes to the marginal distribution customer costs result in small decreases to the distribution revenue allocation for the residential, medium/large commercial & industrial ("M/L C&I"), and lighting customer classes and small increases to the distribution revenue allocation for the small commercial and agricultural customer classes.

(2) <u>Standby Revenues</u>: the distribution revenue allocation calculation reflects the addition of standby revenues in the non-marginal revenue category identified in Attachment B-2, line 17. Standby revenues were mistakenly left out of the distribution non-marginal cost revenues (i.e., distribution revenues directly assigned to a customer class) in the 2016 GRC Phase 2 (A.15-04-012) filed in April 2015, which resulted in an overstatement of the non-assigned distribution revenues that need to be collected in electric rates. This change results in small decreases to the distribution revenue allocation for the residential, small commercial, agricultural, and lighting customer classes and a small increase to the distribution revenue allocation for the M/L C&I customer class because standby revenues are included in the total distribution revenues for the M/L C&I class.

(3) <u>Forecasted 2016 Customers</u>: the forecasted 2016 annual customers have been updated in this filing to reflect changes in forecasted demands. The total number of annual customers did not change only the number of customer identified by kW level. Updates to the forecasted number of customers by kW level result in changes to the allocation of marginal distribution customer cost revenues, which are based on the number of

customers. This change results in small decreases to the distribution revenue allocation for all customer classes except the small commercial class which sees an increase to their distribution revenue allocation due to this change.

(4) Forecasted 2016 Non-Coincident Demand: the forecasted 2016 non-coincident demand determinants have been updated in this filing. Updates to the forecasted 2016 non-coincident demand determinants by customer class result in changes to the allocation of the marginal distribution demand cost revenues which are based on non-coincident demand. This change results in increases to the distribution revenue allocation for the residential, small commercial, agricultural, and lighting customer classes and a decrease to the distribution revenue allocation for the M/L C&I customer class.

ATTACHMENT E

ILLUSTRATIVE NEW CUSTOMER ONLY ("NCO") MARGINAL DISTRIBUTION CUSTOMER COSTS

ATTACHMENT E

SAN DIEGO GAS & ELECTRIC COMPANY ("SDG&E")
TEST YEAR ("TY") 2016 GENERAL RATE CASE ("GRC") PHASE 2, APPLICATION ("A.") 15-04-012
MARGINAL DISTRIBUTION CUSTOMER COSTS

Distribution Customer Marginal Unit Cost by Customer Class Based on New Customer Only ("NCO") Method
Illustrative Marginal Customer Costs --- Not Proposed by SDG&E

Line No.	Description (A)		Secondary (B)	Primary (C)	Transmission (D)	Line No.
1	Customer Marginal Cost Based on NCO Method ($/Customer/Year):					1
2	Residential		$98.44			2
3	Small Commercial					3
4		0 - 5 kW	$221.49	$420.14		4
5		>5 - 20 kW	$306.98	$420.14		5
6		>20 - 50 kW	$486.00	$420.14		6
7		>50 kW	$640.57	$614.99		7
8		Average	$282.14	$447.97		8
9						9
10	Medium/Large Commercial & Industrial					10
11		≤500 kW	$1,470.56	$820.39	$4,086.32	11
12		500 - 12 MW	$2,878.48	$916.81	$5,920.27	12
13		> 12 MW		$918.78	$8,100.44	13
14		Average	$1,499.58	$868.61	$5,106.22	14
15						15
16	Agricultural					16
17		≤20 kW	$402.99	$554.05		17
18		>20 kW	$918.66	$579.87		18
19		Average	$540.92	$578.64		19
20						20
21	Lighting ($/Lamp/Year)		$4.71			21

Note: **Distribution Customer Marginal Unit Cost by Customer Class Based on NCO Method**: the distribution customer marginal unit costs by customer class based on the NCO Method are being provided for comparison purposes, as requested by the Administrative Law Judge's rulings made at the January 26, 2016, Pre-Hearing Conference in this proceeding (A.15-04-012).

FIXED COST REPORT - ATTACHMENT B

SDG&E 2016 GRC PHASE 2 MARGINAL DISTRIBUTION COSTS

REBUTTAL TESTIMONY

Application of SAN DIEGO GAS & ELECTRIC COMPANY (U 902 E) For Authority To Update Marginal Costs, Cost Allocation, And Electric Rate Design.

Application: 15-04-012
Exhibit No.: SDG&E-15

PREPARED REBUTTAL TESTIMONY OF

WILLIAM G. SAXE

ON BEHALF OF SAN DIEGO GAS & ELECTRIC COMPANY IN SUPPORT OF

SECOND AMENDED APPLICATION

CHAPTER 5

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF CALIFORNIA

August 30, 2016

TABLE OF CONTENTS

PREPARED REBUTTAL TESTIMONY OF

WILLIAM G. SAXE

CHAPTER 5

I. OVERVIEW AND PURPOSE

The purpose of this rebuttal testimony is to respond to the direct testimony submitted by the Office of Ratepayer Advocates ("ORA") witnesses Nathan Chau and Louis Irwin, Utility Consumers Action Network ("UCAN") witnesses Garrick F. Jones and William Perea Marcus, The Utility Reform Network ("TURN") witness William Perea Marcus, California Farm Bureau Federation ("Farm Bureau") witness Laura Norin, Solar Energy Industries Association ("SEIA") witness R. Thomas Beach, The Federal Executive Agencies ("FEA") witness Maurice Brubaker, and California City-County Street Light Association ("CALSLA") witness Alison M. Lechowicz regarding marginal distribution customer and marginal distribution demand cost issues. Specifically, I will address recommendations raised by these witnesses and reach the following conclusions regarding those recommendations:

- The California Public Utilities Commission ("Commission") should adopt marginal distribution customer costs in this proceeding based on the Rental Method, proposed by San Diego Gas & Electric Company ("SDG&E") and supported by FEA, because it is the better methodology to use to calculate marginal distribution customer costs compared to the New Customer Only method ("NCO Method"), also called the One-Time Hookup Cost method ("OTHC Method"), proposed by ORA, UCAN, TURN, and CALSLA, as described in Section II.A;
- ORA's and UCAN's proposed adjustment to exclude costs associated with wildfire claims from the calculation of the Administrative and General ("A&G") Loading

Factor for Operations and Maintenance ("O&M") Non-Plant should be approved, but ORA's proposal also to exclude wildfire insurance costs should be rejected, resulting in a revised A&G Loading Factor for O&M Non-Plant of 29.71%, as described in Section II.B.1 and presented in Attachment C;

- UCAN's proposal to modify the O&M costs used in the development of the marginal distribution customer costs by offsetting these O&M costs with the $3,039,000 in 2016 forecasted revenues for service establishment, collection charges, and return check charges ("Miscellaneous Revenues") should be approved, with one modification (i.e., to apply this offset to ALL customers), resulting in an O&M cost offset of $2.10 per customer, as descried in Section II.B.5;
- UCAN's proposed adjustment to the Transformer, Service, and Meter ("TSM") Real Economic Carrying Charge ("RECC") factors used to calculate marginal distribution customer costs based on the Rental Method should be approved. In addition, SDG&E's proposed additional changes to the RECC factors, including updating the RECC meter factors to reflect the factors for smart meters (also referred to as Advanced Metering infrastructure ("AMI") meters) and replacing the use of the single weighted-average TSM RECC factor in the calculation of marginal distribution customer costs with the use of the individual TSM RECC factors (i.e., transformer RECC of 9.19%, service RECC of 8.31%, and average meter RECC of 11.62%) should be adopted, as described in Section II.B.6 and presented in Attachment D;
- The Commission should adopt the updated marginal distribution customer costs proposed by SDG&E, as presented in Attachment A and described in Section II.C, based on the Rental Method that reflects the adjustments to the: (a) A&G Loading

Factor for O&M Non-Plant, (b) O&M costs to reflect the offset of $3,039,000 in 2016 forecasted Miscellaneous Revenues, and (c) TSM RECC factors, mentioned above and described in more details in Sections II.B.1, II.B.5, and II.B.6, respectively;

- If the Commission adopts the marginal distribution customer costs based on the NCO Method, this method should reflect the adjustments to the: (a) A&G Loading Factor for O&M Non-Plant and (b) O&M costs to reflect the offset of $3,039,000 in 2016 forecasted Miscellaneous Revenues, mentioned above and described in more details in Sections II.B.1 and II.B.5, respectively. In addition, the NCO Method should be modified to include the following additional proposed adjustments: (a) ORA's proposal to base the annual new customer numbers on its average 2016-2019 forecasted new meter connections by customer class, as described in Section II.B.7, (b) SDG&E's proposal to use a replacement adder of 3.03% applied to all customers, as described in Section II.B.8, (c) UCAN's proposal to exclude meter replacement labor costs, as described in Section II.B.9, (d) SDG&E's proposal to modify the TSM Present Value Revenue Requirement ("PVRR") factor for meters to be based on the average PVRR for smart meters of 112.05%, as described in Section II.D, and (e) SDG&E's proposal to correct the calculation of the TSM costs per lamp for lighting customers, as described in Section II.D. The NCO Method results reflecting these adjustments are presented in Attachment E, and described in Section II.D;
- SDG&E's proposed updates to the 2014-2015 feeder and local distribution and substation costs to reflect the actual costs that are now available, as described in Section III.C, should be adopted for use in calculating SDG&E's marginal distribution demand costs;

- The load used in the calculation of SDG&E's marginal distribution demand costs should be changed from SDG&E's distribution-system loads to SDG&E's distribution planning forecasted loads, as described in Section III.E;
- The Commission should adopt the updated marginal distribution demand costs proposed by SDG&E, as presented in Attachment A and described in Section III.F, that reflect the adjustments to the (a) A&G Loading Factor for O&M Non-Plant, (b) 2014-2015 feeder and local distribution and substation costs to reflect actual costs, and (c) 2002-2016 load data to reflect distribution planning forecasted loads, described in Sections II.B.1, III.C, and III.E, respectively; and
- The Commission should adopt the updated Equal Percent of Marginal Costs ("EPMC") distribution revenue allocation proposed by SDG&E, as presented in Attachment B and described in Section IV, based on SDG&E's rebuttal testimony updates to the marginal distribution customer and marginal distribution demand costs mentioned above and described in more details in Sections II.C and III.F, respectively.

My rebuttal testimony is organized as follows:

- Section II – Marginal Distribution Customer Costs:

  A. Rental Method versus NCO Method;

  B. Marginal Distribution Customer Cost Calculation Adjustments;

  C. SDG&E Proposed Updated Marginal Distribution Customer Costs Based on Rental Method; and

  D. Revised Illustrative Marginal Distribution Customer Costs Based on NCO Method.

- Section III – Marginal Distribution Demand Costs:
  A. Marginal Distribution Demand Cost Time-Period;
  B. Updated SDG&E Distribution-System Loads for 2014-2016;
  C. Additional SDG&E Proposed Updates to Marginal Distribution Demand Cost Analysis;
  D. Distribution Demand Replacement Costs;
  E. Use of Distribution Planning Forecasted Loads in the Marginal Distribution Demand Regression Analysis; and
  F. SDG&E Proposed Updated Marginal Distribution Demand Costs.
- Section IV – SDG&E Proposed Updated Distribution Revenue Allocation.
- Section V – Summary and Conclusion

My rebuttal testimony also contains:

- Attachment A – SDG&E Proposed Updated Marginal Distribution Costs;
- Attachment B – SDG&E Proposed Updated Distribution Revenue Allocation;
- Attachment C – Revised A&G O&M Non-Plant Loading Factor;
- Attachment D – Revised TSM RECC and PVRR Factors;
- Attachment E – Revised Illustrative NCO Method Calculation Results;
- Attachment F – Revised 2002-2016 Distribution-System Loads and 2014-2015 Feeder & Local Distribution and Substation Costs; and
- Attachment G – Comparison of Marginal Distribution Demand Costs Based on Distribution-System Loads versus Distribution Planning Forecasted Loads.

II. MARGINAL DISTRIBUTION CUSTOMER COSTS

A. Rental Method versus NCO Method

1. Commission Decisions from Two Decades Ago Should Not Set the Precedent on Marginal Distribution Customer Cost Methodology

ORA, TURN, and CALSLA argue that the Commission already has decided in prior decisions that the NCO Method (also referred to as the "OTHC Method") is the better method to calculate marginal distribution customer costs. For this reason, these parties state that the Commission should not change its position on this issue and should continue to use the NCO Method to calculate marginal distribution customer costs in this proceeding.[1]

SDG&E disagrees with ORA, TURN, and CALSLA that prior Commission decisions that adopted the NCO Method, with the most recent of these decisions being issued approximately 20 years ago,[2] should set the precedent for the marginal distribution customer cost methodology adopted in this proceeding. SDG&E agrees with FEA that these claims are misplaced.[3] The methodology to use in developing marginal distribution customer costs has always been a contentious issue in rate design cases, with many twists and turns along the way. For instance, it is interesting to note that ORA actually supported the Rental Method over the NCO Method in the most recent decision cited that adopted the NCO Method, D. 97-12-044. The decision states that:

> *The Office of Ratepayer Advocates (ORA) objects to PG&E's method [NCO Method]* [4] *of allocating revenues for new customer*

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1 ORA Testimony, pp. 1-4 and 1-5; TURN Testimony, pp. 1-2 and 8-11; and CALSLA Testimony, pp. 4-5.

2 Decision (D.) 97-12-044.

3 FEA Testimony, p. 8.

4 In Pacific Gas & Electric Company's ("PG&E") most recent GRC Phase 2 proceeding (2017 GRC Phase 2 Application 16-06-013), PG&E proposed the Rental Method over the NCO Method.

hookups. This is because there is no apparent relationship between the costs imposed for access by a particular customer and the growth attributable to that customer's assigned class in earlier years. ORA raises a valid issue. Why should all of the customers in a particular class face higher or lower customer costs just because a certain number of new customers might be expected to join that class in the future? There is no causative relationship between the existing members of a particular rate class and the cost of a new hookup. Of course, the most efficient way to assign new hookup costs would be to charge each new customer the full cost of its new hookup. For several reasons, the Commission has not historically done that.[5]

This decision goes on to state that "[f]or now, we will adopt PG&E's approach [NCO Method]. However, in future proceedings, we will ask parties to help the Commission to respond more effectively to the equity concerns raised by this issue."[6] It is interesting that parties in this proceeding are trying to claim that theses prior decisions in non-SDG&E proceedings should be used as the basis for adopting the NCO Method in this proceeding, especially given the fact that the Commission clearly stated that it expects parties to present more information in future proceedings to ensure the marginal distribution customer cost methodology used fairly allocates distribution customer costs to customers.

For the reasons stated above, SDG&E recommends that the Commission base its decision on which methodology to use to calculate marginal distribution customer costs on the evidence

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[5] D.97-12-044, p. 7.
[6] D.97-12-044, pp. 7-8.

presented by parties in this proceeding and not on Commission decisions dating back at least two decades ago based on the evidence presented in those non-SDG&E proceedings. As discussed below, SDG&E believes that the Rental Method is the appropriate methodology to use in the development of marginal distribution customer costs in this proceeding because this methodology is based on marginal costs, provides accurate price signals regarding distribution customer costs, and provides more accurate and less volatile allocations of authorized distribution revenue requirements based on distribution customer costs.

2. Rental Method Based on Marginal Costs

ORA and TURN imply that the Rental Method is not based on marginal costs but is more of an embedded cost approach because it calculates the costs for all existing customer hook-up equipment.[7]

ORA and TURN appear to misunderstand the difference between marginal and embedded costs. Marginal customer costs reflect the incremental costs to serve the next customer whereas embedded customer costs reflect the historical costs incurred to serve customers. As explained in my direct testimony,[8] the Rental Method is based on the incremental TSM costs (not historical costs) to serve the next customer and thus, the Rental Method is based on marginal costs. In fact, the NCO and Rental methods use the same incremental TSM costs in the development of marginal distribution customer costs. The difference in these marginal distribution cost methodologies is the conversion of the incremental TSM costs into a cost per customer amount. The Rental Method using the RECC factors to annualize the cost of TSM assets correctly reflects the marginal cost of providing service to the next customer and correctly applies these marginal costs to all customers taking electric service from SDG&E. Applying

[7] ORA Testimony, p. 1-4; and TURN Testimony, pp. 2-3.
[8] SDG&E Direct Testimony of William G. Saxe, Chapter 6, pp. WGS-6 through WGS-9.

marginal costs to all customers does not result in the conversion of the same incremental TSM costs into embedded costs as ORA and TURN seem to imply. Conversely, the NCO Method does not calculate the marginal customer costs to provide service to the next customer but rather calculates the incremental change in total customer costs due to the expected customer growth rate of each customer class. Given its dependency on the customer growth rate by customer class the NCO Method provides customers with the more volatile TSM price signal compared to the Rental Method. As explained below, the NCO Method violates the concept of marginal cost pricing because zero customer growth for a customer class will result in a $0.00 marginal TSM price under the NCO Method while the Rental Method correctly identifies positive TSM costs for the next, or marginal, customer served in this customer class. For this reason, contrary to what ORA and TURN claim, the NCO Method is the distribution customer cost methodology that does not calculate the true marginal costs of the TSM assets for the next customer requiring service.

3. Rental Method Sends More Accurate Price Signal

ORA, TURN, and CALSLA imply that the Rental Method overcharges customers for the cost of their TSM equipment.[9] TURN witness Mr. Marcus goes on to argue that the Rental Method does not reflect a competitive market price because "…it prohibits purchasing equipment, or paying for it up front in hookup charges, and, thus, simulates a market with extreme barriers to entry by relevant participants in that market."[10] He compares the TSM equipment market to the housing market to argue that the Rental Method does not reflect economic reality because it requires everyone to be renters and thus, does not describe a

[9] ORA Testimony, p. 1-4; TURN, p. 7; and CALSLA, p. 5.
[10] TURN Testimony, pp. 1-2.

competitive market.[11] Mr. Marcus acknowledges that in a truly competitive market the TSM equipment costs would be fully paid by new customers when they are hooked up but because that is not the reality of the utility industry, the NCO Method also does not truly reflect a competitive market situation but in his perspective provides a second-best solution.[12]

ORA, TURN, and CALSLA are mistaken when they claim that the Rental Method does not provide an accurate price for TSM equipment and ends up overcharging customers for this equipment. Actually the opposite is true - the NCO Method based on forecasted customer growth rates by customer class assumed in the NCO Method calculations of ORA and UCAN undercharges customers for TSM costs. As explained above, both the Rental and NCO methods use the same incremental cost per TSM assets in their calculation of marginal costs. The Rental Method takes the purchase price of the TSM assets and converts it into a rental price based on the cost of the TSM assets. Conversely, the NCO Method takes that same purchase price of the TSM assets, multiplies it by the number of forecasted new customers and assumed TSM replacements in the customer class, and then divides this dollar amount by the number of total customers in the class to get a cost per customer that neither reflects a rental price or a purchase price of the TSM assets. ORA witness Chau seems to recognize this when he states that under the NCO Method, "[t]hese fully-loaded TSM costs are socialized (shared) by all customers within a class."[13] TURN witness Marcus also seems to understand that the NCO Method does not send the correct price signal to customers when he states that "…the most economically efficient method for capturing the costs of electric customer-access equipment would be in the form of a <u>customer</u> hookup fee that would charge the utility's access equipment costs to the

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[11] TURN Testimony, pp. 4-5.
[12] TURN Testimony, pp. 6-7.
[13] ORA Testimony, p. 1-7, lines 16-17.

customer at the time that the equipment is first installed,"[14] which Mr. Marcus acknowledges the NCO Method does not do because it assigns the customer hookup costs to the customer class.[15] For this reason, the Rental Method reflects an accurate rental price for TSM equipment to fully recover those costs from the customer whereas the NCO Method reflects an understated price that does not represent the cost of the TSM equipment and thus, will not fully recover the TSM costs from the customer.

ORA witness Chau implies that because the Rental Method collects a constant annual charge over the life of the TSM assets, this method provides a price based on the value of the TSM assets instead of its costs.[16] Again, as explained above, both the Rental and NCO methods use the same TSM costs. Through the use of the RECC factors to annualize the TSM costs, the Rental Method contains depreciation charges that account for the plant investment that is "used up," causing the need for eventual replacement. By annualizing the TSM costs, the Rental Method correctly provides an annual rental price to fully recover the cost of the TSM assets from the customer. Conversely, the NCO Method calculates a price for the TSM assets that varies considerably depending on the assumed customer class growth rate and not necessarily in response to changes in the TSM costs. For example, while ORA correctly identifies incremental unit TSM costs for the agricultural customer class, it calculates a TSM marginal price of $0 for agricultural customers under the NCO Method because the customer growth rate for the agricultural customer class is assumed to be zero.[17] This shows that the NCO Method is not a better approach for calculating marginal TSM costs as ORA claims because this method fails to calculate a positive marginal TSM price for agricultural customers despite the identification of

[14] TURN Testimony, p. 6.
[15] TURN Testimony, p. 7.
[16] ORA Testimony, p. 1-6.
[17] "ORA Testimony Chapter 1 Marginal Distribution Customer Access costs Consolidated Model.xlxs" workpaper file.

incremental TSM costs for agricultural customers. ORA witness Chau appears to understand this flaw with the NCO Method when he states that "[o]ften a floor of zero is imposed on the net growth rate to avoid calculating nonsensical negative marginal costs."[18] However, even imposing a customer class growth rate floor of zero as ORA did produces nonsensical results under the NCO Method, because a zero growth rate means a zero TSM marginal price. This clearly identifies one of the major flaws of the NCO Method, which is that under this marginal distribution customer cost methodology, results can change significantly from year to year based on changes in customer class growth rates rather than changes in TSM costs.

TURN witness Marcus is confused when he claims that the NCO Method better represents a competitive market compared to the Rental Method. Mr. Marcus tries to use the housing market as support for this claim by arguing that the Rental Method assumes that everyone is required to rent a home and no one is allowed to purchase a home, which does not reflect economic reality.[19] However, just the opposite is true. The housing analogy he uses actually provides support for the Rental Method not the NCO Method because the Rental Method correctly reflects the reality that all customers, whether owners or renters, face the same marginal costs. The marginal cost to both the owner and renter is the same because there is opportunity cost that an owner would incur by occupying the home equal to the rent that could be charged for the home. The same logic applies for renting versus purchasing TSM assets. Even if a customer decides to purchase TSM equipment, the Rental Method is still the appropriate method to use in the development of marginal distribution customer costs because it uses the RECC factors to annualize the cost of TSM assets, which correctly accounts for the opportunity cost of the purchase. In contrast, the NCO Method does not represent a competitive

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[18] ORA Testimony, p. 1-8, lines 14-15.
[19] TURN Testimony, p. 4.

market because it assumes that everyone purchases the TSM assets, which does not reflect the reality of the utility industry. More importantly, it fails to provide an efficient price signal for such assets because it only applies such costs to forecasted new customers and then divides these new customer costs over all customers (not just new customers) to derive a price that neither reflects the rental or purchase price of the TSM assets.

For the reasons stated above, the Rental Method not the NCO Method provides a more accurate price signal for TSM costs.

4. Rental Method More Accurately Allocates Authorized Distribution Revenues

ORA, TURN, and CALSLA claim that the NCO Method better reflects cost causation for TSM equipment because the NCO Method only considers TSM costs for new customers while the Rental Method overcharges customers for TSM equipment.[20] ORA, TURN, and CALSLA go on to argue against the Rental Method because they state that the Rental Method assigns marginal distribution customer costs to all customers even though TSM costs have little or no value once installed.[21] TURN witness Marcus states that "[a]ssigning hookup charges to the class, while a second-best solution from the point of view of economic efficiency, avoids subsidies among classes for these customer hookup charges because it assures that each class pays for its own hookups."[22] ORA witness Chau states that "…the assumptions built in to the Rental Method are nonsensical for hook ups since costs are covered entirely up-front pursuant to Rules 15 and 16."[23]

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[20] ORA Testimony, pp. 1-4 through 1-7; TURN Testimony, pp. 5-7; and CALSLA Testimony, p. 5.
[21] ORA Testimony, p. 1-6; TURN Testimony, pp. 3-4; and CALSLA Testimony, p. 5.
[22] TURN Testimony, p. 7.
[23] ORA Testimony, pp. 1-5, line 25 through 1-6, line 1.

The arguments provided by ORA, TURN, and CALSLA as to why the NCO Method reflects cost causation and improves economic efficiency would only have merit if SDG&E's customers actually paid for TSM costs upfront when getting hooked up for electric service. As stated above, this is not the case. Contrary to what ORA states, TSM hookup costs are not fully collected at the time of hookup. The Commission has adopted the concept of TSM allowances under Rules 15 and 16 that collect the TSM cost allowances over time from all customers through authorized revenue requirements based on customer hookup costs associated with the allowances provided under Rules 15 and 16. Basically, developers receive an allowance towards the cost of new customer hookups from SDG&E and these hookup costs are then recovered over time as part of the authorized distribution revenue requirement that SDG&E is proposing to allocate based on the marginal distribution customer costs adopted in this proceeding. The development of marginal distribution customer costs based on the Rental Method is in fact consistent with the Rule 15 and Rule 16 cost recovery methodology because it calculates the TSM marginal costs based on recovery of TSM costs from customers over the life of the TSM assets. Therefore, contrary to what ORA, TURN, and CALSLA claim, a marginal TSM price needs to be assigned to all customers to prevent subsidies associated with recovering TSM costs from occurring between customer classes, which the Rental Method correctly does and the NCO Method fails to do.

Because customers do not pay TSM hookup costs upfront prior to taking electric service from SDG&E, the Rental Method doesn't overcharge for customer connection costs as implied by parties but rather the NCO Method understates customer connection costs. As explained above, the NCO Method fails to calculate the marginal customer costs to provide service to the next customer but rather calculates the incremental change in total customer costs due to the assumed customer growth rate in each customer class. By applying TSM costs to only expected new customers in a given year and then dividing these incremental costs by all customers, the NCO Method is economically inefficient because it generally understates marginal distribution customer costs and thus, when applied for distribution revenue allocation purposes, understates the customer connection costs.

SDG&E agrees with FEA that applying the marginal distribution costs based on the NCO Method can lead to volatile distribution revenue allocations.[24] Customer classes that are growing rapidly during a given GRC Phase 2 period could experience large increases in distribution revenue allocations whereas customer classes that are growing less over that same period of time will experience much smaller distribution revenue allocations, independent of whether actual TSM costs have changed. This can result in significant revenue subsidies between customer classes based on the timing of when customer growth occurs within a class and not necessarily due to the cost of customer hookups incurred by SDG&E and reflected in its authorized distribution revenue requirement.

As stated above, another argument given by ORA, UCAN, CALSLA as to why the Rental Method does not calculate marginal cost is the claim that TSM assets have little if any value once installed because these assets have been installed to serve one customer. While SDG&E disagrees that the salvage value argument is important in deciding the appropriate marginal distribution customer cost methodology to use in this proceeding, SDG&E wants to at least respond to the notion that TSM assets have little or no value once installed. Obviously, smart meters have value because meters can be moved if a customer discontinued service with SDG&E. But more importantly is the fact that transformers, which reflect the majority of TSM costs, are generally installed to serve more than one customer (i.e., the smallest single-phase and

[24] FEA Testimony, p. 6.

three-phase transformers are assumed to serve 22 and 60 residential customers, respectively). A decrease in one customer would free up capacity on the transformer to serve other customers and thus, transformers clearly have value after installation. For this reason, the argument that the Rental Method somehow does not calculate marginal cost correctly because TSM assets have no value after installation has no merit.

For the reasons stated above, marginal distribution customer costs based on the Rental Method rather than the NCO Method will more accurately allocate authorized distribution revenues to customers.

B. Marginal Distribution Customer Cost Calculation Adjustments

1. Modification to A&G Loading Factor for O&M Non-Plant

ORA and UCAN propose adjustments to the A&G Loading Factor for O&M Non-Plant used in the calculation of marginal distribution customer costs.[25] ORA proposes to exclude what it defines as "extraordinary events" from the calculation of this A&G loader, specifically costs associated with wildfire claims and wildfire insurance. UCAN proposes revision to the Account 925 costs used in the calculation of this A&G loader based on SDG&E GRC Phase 1 (Application 14-11-003) Account 925 amounts, including the elimination of cost associated with wildfire claims.

SDG&E agrees with ORA and UCAN that costs associated with wildfire claims should be excluded from the calculation of this A&G loader because these wildfire claim costs are not expected to continue going forward. However, SDG&E disagrees with ORA's exclusion of wildfire insurance costs from this A&G loader because insurance costs associated with wildfires are forecasted to continue into the future. For this reason, SDG&E proposes that the Commission adopt the 5-year average A&G Loading Factor for O&M Non-Plant based on 2009-2013

[25] ORA Testimony, p. 1-13; and UCAN Testimony, pp. 20-21.

historical costs excluding costs associated with wildfire claims for use in calculating marginal distribution customer and demand costs, resulting in a change in the loading factor from 38.51% to 29.71%, as shown in Attachment C.

2. Accounts 586 and 587 O&M Costs

UCAN proposes to replace the 2009-2013 Accounts 586 and 587 costs in the 5-year average O&M calculation used in the calculation of marginal distribution customer costs with just the 2013 Accounts 586 and 587 costs because of changes in these costs due to AMI implementation, also referred to as smart meter implementation.[26] UCAN states that this change is needed because "[i]t is unreasonable to calculate marginal costs by averaging embedded costs reflecting past years when old technology was used that has already been supplanted."[27]

SDG&E disagrees with UCAN's proposal to modify the Accounts 586 and 587 O&M costs used in the development of O&M costs associated with marginal distribution customer costs. The O&M costs that SDG&E uses in the development of marginal distribution customer costs are 2013 costs that are allocated between customer-related and demand-related costs using the 5-year allocation factors based on 2009-2013 recorded O&M costs. Because Accounts 586 and 587 O&M costs are associated with meters, 100% of these costs are allocated to customer-related costs, which means that the specific Accounts 586 and 587 costs used in developing marginal distribution customer costs are 2013 costs, as UCAN suggests. However, UCAN is proposing to modify the 5-year O&M allocation factors used to allocate distribution O&M costs between customer-related and demand-related costs by using 2013 Accounts 586 and 587 costs for all five years. The reason that the allocation factors are developed based on an average of five years of distribution O&M cost data is to smooth out any anomalies that might occur in the

[26] UCAN Testimony, pp. 19-20.
[27] UCAN Testimony, p. 19.

costs in any given year. It would be inappropriate to modify the development of the 5-year allocation factors as UCAN suggests by replacing 2009-2012 Accounts 586 and 587 costs with 2013 costs because changes in Accounts 586 and 587 costs could have impacts on other distribution O&M Account costs used in the calculation. For this reason, it would be inconsistent to use a single year of costs (2013) for Accounts 586 and 587 instead of five years of costs (2009-2013) as is used for the other distribution O&M Accounts in the development of the 5-year O&M allocation factors. SDG&E recommends that the O&M allocations factors be based on an average of 2009-2013 O&M costs for all distribution Accounts and thus, the Commission should reject UCAN's proposal regarding the modification of Accounts 586 and 587 costs used in the development of the 5-year O&M allocation factors.

3. <u>Average Number of Residential Customers Served Per Transformer</u>

UCAN calculates an average number of residential customers per transformer based on SDG&E's TSM costs to be 9.32 customers and states that in response to UCAN DR 2-17, SDG&E indicated that the actual residential customers per transformer is 9.97 customers. For this reason, UCAN proposes to increase the number of residential customers per transformer for all customer sizes where the transformer serves four or more customers by 7%.[28]

SDG&E disagrees with UCAN's proposed change in the number of residential customers assumed to be served per transformer. In response to the referenced UCAN DR 2-17 data request, SDG&E provided the average number of residential customers at a given point in time, which happened to be 9.97 customers, whereas the 9.32 customer number reflects the average number of residential customers per transformer based on distribution planning engineering criteria regarding the number of customers by kW size that can be served on each type of transformer. For instance, the distribution planning engineering criteria indicates that as many as

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[28] UCAN Testimony, p. 18.

22 residential customers with annual load between 0-2 kW and 60 residential customers with annual load between 0-2 kW are assumed to be served on a signal-phase 25 kW transformer and three-phase 75 kW transformer, respectively. It would be inappropriate to assume that the number of customers for every type of transformer serving four or more customers can be increased by 7% as UCAN proposes. Under UCAN's proposal, the number of 0-2 kW customers served on a single-phase 25 kW transformer and three-phase 75 kW transformer would be increased to approximately 24 and 64 customers, respectively, which is more customers than SDG&E's distribution planning engineering criteria identifies as should be served on these transformer types. For this reason, SDG&E recommends that the Commission reject UCAN's proposed adjustment to the number of residential customers per transformer because the number of customers SDG&E identified per transformer is supported by the distribution planning engineering criteria.

4. Tree Trimming and Pole Brushing Costs

UCAN proposes changes to O&M costs assigned to customer-related and demand-related distribution costs based on the percentage of tree trimming and pole brushing costs (within Account 593) assumed to be customer-related. UCAN proposes that tree trimming costs assigned to customer-related costs be reduced from approximately 12% to 2% and pole brushing costs assigned to customer-related costs be reduced from approximately 12% to 0%. UCAN states that based on the 5-year average of these costs, where tree trimming reflected 53.8% and pole brushing reflected 9.2% of Account 593 costs, this change reduces the allocation of Account 593 costs assigned to customer-related costs from about 12% to between 5-6%.[29]

SDG&E disagrees with UCAN's proposal to assign less of the tree trimming and pole brushing costs to customer-related costs. While SDG&E does not disagree that based on recent

[29] UCAN Testimony, p. 20.

historical data, less than 12% of tree trimming and pole brushing costs is associated with customer-related cost, SDG&E assigns the total O&M costs between customer-related and demand-related costs based on distribution plant assets. For this reason, it would inappropriate to assign tree trimming and pole brushing costs separately because total O&M costs are assigned to customer-related and demand-related costs based on a single allocation factor. Accepting UCAN's tree trimming and pole brushing cost proposal would require all O&M costs to be assigned to customer-related and demand-related separately, which is not possible because SDG&E does not have customer-related and demand-related splits for all O&M costs. This is the reason that SDG&E proposed the development of a single allocation factor for total O&M costs between customer-related and demand-related functions because this approach is possible and reasonable. For the reason stated above, SDG&E recommends that the Commission reject UCAN's proposal to allocate tree trimming and pole brushing costs separately because this approach is not workable and inconsistent with the allocation of other O&M costs.

5. O&M Cost Offset from 2016 Miscellaneous Revenues

UCAN states that "SDG&E has not included revenue offsets for several different types of miscellaneous revenue that it receives from tariffed service charges to customers (for service establishment, field collection, and returned check). These revenue credits offset costs paid by SDG&E for customer accounting and customer-related distribution O&M accounts." [30] For this reason, UCAN proposes to offset the marginal customer O&M costs used to develop the marginal distribution customer costs in this proceeding with the $3,039,000 in 2016 forecasted electric tariff service charge revenues ("Miscellaneous Revenues"), which results in an offset of

[30] UCAN Testimony, p. 22.

$2.111 per customer (except lighting customers, which UCAN states is highly unlikely to ever pay these fees) per year.[31]

SDG&E agrees with UCAN's proposal to use the 2016 Miscellaneous Revenues to offset O&M costs. Marginal costs should not reflect costs associated with Miscellaneous Revenues because these revenues are not included in base rate revenues and thus, UCAN's proposal to offset the forecasted 2016 O&M costs with the forecasted 2016 Miscellaneous Revenues is a reasonable approach to remove Miscellaneous Revenue costs from the O&M costs.

One modification that SDG&E proposes to UCAN's proposal is to apply this O&M cost offset to all customers, including the lighting customers that UCAN excluded from the offset. Because O&M costs are assigned to all customers, including lighting customers, SDG&E believes that this Miscellaneous Revenues offset should be applied to all customers. For this reason, SDG&E proposes that the Commission adopt a 2016 Miscellaneous Revenues offset of $2.10 per customer per year, based on dividing the $3,039,000 in forecasted 2016 Miscellaneous Revenues by the forecasted 2016 average number of total customers of 1,445,386, for use in calculating marginal distribution customer costs.

6. TSM RECC Factor

UCAN proposes that the weighted-average RECC factor calculation be modified to exclude the "Protective Devices & Capacitors" (Account 368.2) and "Installations on Customer Premises" (Account 371) equipment because neither of these items is required for customer-access and because these items were not included in the PVRR calculations for the NCO Method.[32]

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31 UCAN Testimony, p. 22.
32 UCAN Testimony, p. 23.

SDG&E agrees with UCAN's proposed weighted-average TSM RECC factor change. While the equipment UCAN identifies are used at least for some customer-access installations, SDG&E agrees that for consistency purposes, these equipment items should be eliminated in the weighted-average TSM RECC factor calculation. In addition, SDG&E proposes two other changes to the weighted-average TSM RECC factor calculation. First, the "Services Overhead" (Account 369.1) item also should be eliminated from the weighted-average RECC calculation because marginal distribution customer costs are based on underground service. Second, the RECC factors used for meters should be updated to reflect the factors for smart meters. Because SDG&E's meters have been replaced with smart meters pursuant to D.07-04-043, the RECC factors used should be changed to reflect the factors for smart meters, which are 11.72% for "Smart Meters" (Account 370.11) and 11.59% for "Meter Installations-Smart Meter" (Account 370.21). With the elimination of the TSM RECC factors for "Protective Devices & Capacitors," "Installations on Customer Premises," and "Services Overhead," and the change in the RECC factors for meters, the resulting weighted-average TSM RECC factor would be 9.40%, as presented in Attachment D. However, as explained below, SDG&E proposes to replace the use of the weighted-average TSM RECC factor with the use of the individual TSM RECC factors in the marginal distribution customer cost calculation.

For simplicity purposes, SDG&E has used the weighted-average TSM RECC factor in the calculation of marginal distribution customer costs based on the weighting of SDG&E's actual costs associated with TSM installations. However, the changes proposed to the weighted-average TSM RECC factor calculation raise the question of whether the use of a weighted-average TSM RECC factor is still appropriate, especially given the fact that the weighting itself no longer reflects actual SDG&E TSM installation costs with these changes. Applying a single weighted-average RECC factor assumes that the weighting of the TSM costs assigned customer classes are equal to the weighting of the TSM factor, which is not correct. For instance, TSM costs for some customers do not include transformer costs and/or meter costs and thus, it would be incorrect to use the weighted-average TSM RECC factor to calculate marginal distribution customer costs for these customers. For this reason, consistent with the use of individual TSM PVRR factors in the NCO Method, SDG&E recommends that the Commission adopt the individual TSM RECC factors, as presented in Attachment D, for use in calculating marginal distribution customer costs based on the Rental Method instead of a single weighted-average TSM RECC factor.

7. <u>New Customer Calculation for NCO Method</u>

ORA witness Nathan Chau argues that the use of the annual change in customers to forecast new customers in the NCO Method "…obscures the number of new connections since these growth rates fail to capture the number of new customers in isolation of those terminating service or switching schedules."[33] For this reason, ORA proposes to use its average 2016-2019 forecasted annual number of customers per customer class based on 2011-2015 new meter installations in the NCO Method.[34]

SDG&E agrees with ORA that new meter installations is a better representation of annual new customers that require new TSM hook ups. For this reason, SDG&E agrees that ORA's average 2016-2019 forecast of new customers per customer class based on SDG&E's historical 2011-2015 new meter installations should be used to develop the new customers by customer class in the calculation of marginal distribution customer costs under the NCO Method.

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[33] ORA Testimony, p. 1-8, lines 9-11.
[34] ORA Testimony, pp. 1-8 through 1-11.

8. Replacement Cost Factor for NCO Method

ORA proposes to only include replacement costs associated with new connections made in a given year instead of basing the replacements on existing customer connections.[35] ORA states that replacement costs need to be included for new connections because these obligations impose the obligation to maintain that equipment going forward. However, ORA argues that replacement costs don't need to be included for existing connections because "…customer turnover and temporary vacancies do not impose any additional obligations to maintain the access equipment at the margin because this obligation was placed on the utility at the time of installation.[footnote excluded] Moreover, SDG&E did not include replacement costs in calculating marginal distribution demand costs 'because these costs are not growth related'."[36]

SDG&E disagrees with ORA that replacements associated with existing connections should not be included in the NCO Method calculation. Regardless of when the replacement obligation was imposed on SDG&E, the key is that SDG&E is obligated to replace TSM equipment when needed and thus, there is a cost associated with replacing this TSM equipment that should be included in the marginal customer cost calculation.

As mentioned above, ORA tries to support its decision to exclude replacements for existing connections by claiming that SDG&E did not include replacement costs in its marginal distribution demand cost calculation because these costs are not growth related. This comparison is not appropriate because marginal distribution demand costs are specifically driven by incremental demand, which is the reason replacement demand costs are not included in the calculation. SDG&E's marginal distribution demand costs are calculated by dividing incremental demand costs by incremental distribution load and thus, replacement costs should

[35] ORA Testimony, p. 1-12.
[36] ORA Testimony, p. 1-12, lines 9-14.

not be included in the marginal distribution demand cost calculation, as explained in Section III.D below. Conversely, marginal distribution customer costs are looking at costs associated with adding a customer to the SDG&E distribution system, which should include both the incremental costs of the TSM assets and the costs for the eventual replacement of those assets in the calculation. Through the use of the RECC factors to annualize the TSM costs, the Rental Method contains depreciation charges that account for the plant investment that is "used up," causing the need for eventual replacement.

If the NCO Method is ultimately adopted by the Commission in this proceeding, SDG&E agrees with UCAN[37] that the NCO calculation should reflect replacements applied to all customers and not just new connections as ORA proposes. In Attachment E of my February 9, 2016 direct testimony (Chapter 6), I presented an illustrative NCO Method calculation that had been used by parties in SDG&E's previous GRC Phase 2 proceedings that included a replacement rate of 1.5%.[38] SDG&E believes that the 1.5% replacement rate was used because this replacement rate had been adopted in one of the more recent Commission decisions adopting the NCO Method that parties cite.[39] SDG&E recommends that this replacement rate be updated based on the current book lives of SDG&E's TSM assets, which are 33 years for transformers (resulting in a replacement rate of 3.03%), 48 years for underground services (resulting in a replacement rate of 2.08%), and 15 years for meters (resulting in a replacement rate of 6.67%). Based on these TSM replacement rates applied to total TSM costs by customer class, the weighted-average replacement rate by customer class would actually be different by customer class due the differences in TSM costs by class. However, SDG&E is not proposing to establish class different replacement rates. Instead, for simplicity purposes, SDG&E recommends that the

[37] UCAN Testimony, pp. 24-25.
[38] SDG&E 2012 GRC Phase 2, A.11-10-002, Testimony of Division of Ratepayer Advocates, p. 3-14.
[39] D.97-03-017, p. 34.

Commission adopt a 3.03% replacement rate to use in the calculation of marginal distribution customer costs under the NCO Method because this is the replacement rate based on the book life of SDG&E transformers, which represents the majority of the TSM costs to serve most SDG&E customers.

9. Exclusion of Meter Replacement Labor Costs

UCAN proposes removing meter-replacement labor costs in the NCO Method because the labor costs for replacement of meters is already included in the O&M costs used in the marginal distribution customer cost calculation.[40]

SDG&E agrees with UCAN's proposal to exclude labor costs from the meter replacement costs included in the NCO Method calculation. For this reason, SDG&E recommends that the Commission approve the reduction in average replacement meter costs by customer class, as proposed by UCAN, for use in calculating marginal distribution customer costs under the NCO Method.

C. SDG&E Proposed Updated Marginal Distribution Customer Costs Based on Rental Method

SDG&E's proposed updated marginal distribution customer costs based on the Rental Method in this rebuttal testimony, as shown in Attachment A, reflect the adjustments to the: (a) A&G Loading Factor for O&M Non-Plant, (b) O&M costs to reflect the offset of $3,039,000 in 2016 forecasted Miscellaneous Revenues, and (c) TSM RECC factors, described above. SDG&E recommends that the Commission adopt SDG&E's proposed updated marginal distribution customer costs based on the Rental Method, as presented in Attachment A.

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[40] UCAN Testimony, pp. 23-24.

D. Revised Illustrative Marginal Distribution Customer Costs Based on NCO Method

As stated above, SDG&E disagrees with the use of the NCO Method to calculate marginal distribution customer costs in this proceeding and recommends that the Commission adopt SDG&E's proposed updated marginal distribution customer costs based on the Rental Method, presented in Attachment A. However, if the Commission decides to adopt the NCO Method for allocating marginal distribution customer costs in this proceeding, the NCO Method calculation should reflect the adjustments to the: (a) A&G Loading Factor for O&M Non-Plant, (b) O&M costs to reflect the offset of $3,039,000 in 2016 forecasted Miscellaneous Revenues, (c) replacement adder of 3.03% for all customers, and (d) exclusion of labor costs for meter replacements, described above. In addition, as mentioned above, SDG&E proposes changes to the TSM RECC factors for meters to reflect the RECC factors for smart meters. For consistency purposes, SDG&E also proposes to change the PVRR factors for meters to reflect the PVRR factors for smart meters, which are 112.99% for "Smart Meters" (Account 370.11) and 111.72% for "Meter Installations-Smart Meter (Account 370.21) resulting in a weighted-average PVRR factor of 112.05% for smart meters, as shown in Attachment D. Finally, the revised NCO Method calculations should also reflect a correction to the illustrative NCO calculation for lighting customers provided in Attachment E of my direct testimony (Chapter 6). The NCO calculation for lighting customers mistakenly labeled the TSM costs as the "costs per customer," when in fact these costs were the "costs per lamp," which resulted in the marginal distribution customer costs for lighting customers to be understated when these costs were applied under the NCO Method. The revised illustrative NCO calculation results presented in Attachment E reflect the six adjustments described above.

III. MARGINAL DISTRIBUTION DEMAND COSTS

A. Marginal Distribution Demand Cost Time-Period

ORA states that SDG&E deviates from the standard practice recommended by the National Economic Research Associates ("NERA") by using 12 years of historical data (2002-2013) and only 3 years of forecasted data (2014-2016) in its marginal distribution demand cost regression analysis without providing justification for this change. ORA argues that 2002 and 2003 data should be excluded from the marginal distribution demand cost regression analysis because these years were right in the midst of the California energy crisis recovery period, and adding these years influences the load trend, substantially bumping the entire trend upward. For this reason, ORA proposes to only include 10 years of historical data (2004-2013) and 3 years of forecasted data (2014-2016) in its marginal distribution demand cost regression analysis.[41]

SDG&E agrees with the Farm Bureau that there is no need to remove 2002 and 2003 data from the marginal distribution demand cost regression analysis because these years are not outliers, as ORA claims.[42] ORA only considered the change in load when it deemed these years to be outliers, but as the Farm Bureau correctly states, the important thing to look at is the ratio of incremental distribution investment to incremental load, which shows 2002 and 2003 are not outliers.

ORA is correct that the NERA regression methodology recommends using 10 years of historical and 5 years of forecasted data. However, as explained in my direct testimony, SDG&E only had 3 years of forecast data available, which is the reason SDG&E chose in this proceeding (as it has in its previous two GRC Phase 2 proceedings) to use 12 years of historical data in the regression analysis to maintain the fifteen data points (12 years of historical data and 3 years of

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41 ORA Testimony, pp. 2-2 and 2-3.
42 Farm Bureau Testimony, p. 42.

forecasted data).[43] SDG&E believes that maintaining a sufficient number of data points for the regression analysis is important, which is the reason it chose to maintain the fifteen years of data points that the NERA methodology recommends by including two additional years of historical data.

For the reasons discussed above, the Commission should reject ORA's proposal to eliminate the 2002 and 2003 data from the marginal distribution demand cost regression analysis.

B. Updated SDG&E Distribution-System Loads for 2014-2016

ORA proposes that the 2014 forecasted distribution-system load that SDG&E included in its marginal distribution demand cost calculation should be updated to reflect the SDG&E actual weather-normalized 2014 distribution-system load, which is now available.[44] ORA also proposes to update the forecast for SDG&E's 2015 and 2016 distribution-system loads used to calculate marginal distribution demand costs with the California Energy Commission ("CEC") 2015 revised forecasts for those years.[45]

SDG&E agrees with ORA that the 2014 forecasted distribution-system load should be updated to reflect SDG&E's actual weather-normalized 2014 distribution-system load because this load data is now available. As explained in the rebuttal testimony of SDG&E witness Kenneth E. Schiermeyer, SDG&E proposes a modification in its weather-normalization process.[46] SDG&E's proposed actual weather-normalized 2014 distribution-system load of 4,279 MW is lower than the 4,365 MW that ORA proposes because of the change in SDG&E's weather-normalization process.

[43] SDG&E Direct Testimony of William G. Saxe, Chapter 6, p. WGS-4, lines 19-22.
[44] ORA Testimony, pp. 2-4 and 2-5.
[45] ORA Testimony, pp. 2-5 through 2-7.
[46] SDG&E Rebuttal Testimony of Kenneth E. Schiermeyer, Chapter 4.

SDG&E also agrees with ORA that the 2015 and 2016 distribution-system loads used in the marginal distribution demand cost analysis should be updated to reflect the most current load information available. Because SDG&E's actual 2015 distribution-system load data is now available, SDG&E proposes that its forecasted 2015 distribution-system load should be updated to reflect SDG&E's actual 2015 weather-normalized load, as ORA proposes. Regarding the 2016 forecasted distribution-system load, SDG&E agrees with ORA that the 2016 forecasted load should be based on the CEC 2015 revised forecast for 2016 adjusted for transmission load and Additional Achievable Energy Efficiency ("AAEE"), as ORA proposes. SDG&E's proposed updated 2016 forecasted load of 4,438 MWs is a little higher than ORA's proposed 2016 forecasted load of 4,414 MWs because of lower calculated transmission load due to the modification to SDG&E's weather-normalization process, as described in Mr. Schiermeyer's rebuttal testimony. SDG&E's revised weather-normalized 2014-2015 and revised forecasted 2016 distribution-system loads are presented in Attachment F.

C. Additional SDG&E Proposed Updates to Marginal Distribution Demand Cost Analysis

As stated above, SDG&E is proposing a modification to its weather-normalization process, as addressed in the rebuttal testimony of Mr. Schiermeyer. For this reason, SDG&E proposes revisions to the 2002 through 2015 weather-normalized actual distribution-system loads to reflect this modified weather-normalization process change. Attachment F presents the revised 2002-2015 weather-normalized and 2016 forecasted distribution-system loads.

In addition, SDG&E proposes to update the feeder and local distribution and substation costs used in the marginal distribution demand cost regression analysis to reflect actual 2014 and 2015 distribution cost data. As mentioned above regarding the updates to the distribution-system load data, SDG&E now has actual 2014 and 2015 data and thus, SDG&E believes the marginal distribution demand cost regression analysis should be updated to reflect actual 2014 and 2015 cost data. Attachment F presents the revised feeder and local distribution and substation costs proposed by SDG&E for use in its marginal distribution demand cost analysis.

D. Distribution Demand Replacement Costs

UCAN proposes that marginal distribution demand costs should include SDG&E's marginal distribution capital replacement costs. UCAN states that "[b]y not including replacement costs, SDG&E's marginal cost methodology assumes that, once a piece of equipment is added, the utility will always replace that equipment, yet the future customers who benefit from the replacement—through receiving continued service—will never have to pay for it. Instead, the cost of the equipment would be recovered from all current customers as a non-marginal cost included in the EPMC multiplier."[47] UCAN goes on to state that "…SDG&E's view of this issue is based on the assumption that marginal cost <u>only</u> applies to <u>new demand</u> and not to the retention of existing demand….It is not reasonable to assume that customers in areas without load growth should bear no responsibility for the cost of O&M and capital maintenance replacements necessary to keep the existing system available for their use."[48] For this reason, UCAN proposes the inclusion of replacement distribution demand costs, which it finds to be about 50% of SDG&E's capital spending on the distribution system, as it identifies in Table 9.

SDG&E disagrees with UCAN that distribution demand costs not associated with load growth, such as replacement costs, should be included in the calculation of marginal distribution demand costs. UCAN appears to misunderstand the purpose of developing marginal distribution demand costs in this proceeding, which is to develop a marginal cost per kW to add incremental

[47] UCAN Testimony, pp. 25-26.
[48] UCAN Testimony, p. 28.

demand to the SDG&E distribution system. These marginal costs are developed by regressing the incremental distribution demand costs needed to add load to the distribution system by the incremental distribution load added. Replacement costs should not be included in these marginal costs because these replacement costs are not associated with the incremental load being added to the distribution system. The annual $/kW marginal distribution demand costs based on the RECC factors contains depreciation charges that account for the eventual replacement of the distribution demand investment made to meet the load growth. For this reason, the marginal distribution demand cost calculation should only reflect the cost of adding demand to the distribution system and thus, should exclude costs not associated with load growth such as replacement costs as SDG&E's calculation correctly does.

UCAN incorrectly argues that not including replacement costs in the marginal distribution demand cost analysis results in future customers not having to pay for the cost of substation and feeder & local distribution costs and customers in areas without load growth not paying for the costs to maintain the existing distribution system for their use. This is not correct because SDG&E is developing an annual $/kW for substations and feeder & local distribution costs that applies to all customers, both existing and future customers, and customers in high-growth and low-growth areas.

UCAN also implies that by not including replacement costs in the marginal distribution demand costs, SDG&E is understating marginal distribution demand costs and thus, overstating the EPMC multiplier. However, just the opposite is true. UCAN is overstating the marginal distribution demand costs by including replacement costs because it inconsistently adds distribution demand costs without adjusting the load used in the marginal distribution demand regression analysis to reflect the costs added. As described above, replacement costs should not be included in the marginal distribution demand cost analysis because these marginal costs should be based on adding load. However, if replacement costs are included, the distribution load used in the marginal distribution demand regression analysis needs to be adjusted to include the distribution load associated with the replacement costs. By increasing distribution demand costs used in the marginal distribution demand cost regression analysis to reflect the addition of replacement costs but not increasing the distribution load to reflect the inclusion of these distribution replacement costs, UCAN significantly overstates the marginal distribution demand costs and thus, understates the EPMC multiplier.

For the reasons stated above, the Commission should reject UCAN's proposal to include distribution replacement costs in the calculation of marginal distribution demand costs.

E. Use of Distribution Planning Forecasted Loads in the Marginal Distribution Demand Regression Analysis

SEIA questions why SDG&E calculates its marginal distribution demand costs by using a regression of distribution investments versus annual distribution peak loads, instead of distribution investments versus non-coincident demand. SEIA states that "[i]t would be fundamentally inconsistent for the utility to calculate its distribution marginal costs on the basis of the annual peak demand on the distribution system, yet to charge customers for those costs based 100% on individual customer's non-coincident demands." [49]

The purpose of the marginal distribution demand cost regression analysis is to calculate the marginal demand costs ($/kW) based on incremental load added to the SDG&E distribution system. In the marginal distribution cost regression analysis, SDG&E used its distribution-system load to determine the annual incremental load added to the SDG&E distribution system. As stated in the direct testimony of SDG&E witness John Baranowski, SDG&E's distribution

[49] SEIA Testimony, p. 29, lines 6-9.

system is designed to meet the non-coincident peak demand of each circuit and substation[50] and thus, the incremental distribution-system load SDG&E adds is designed to meet non-coincident peak demand. For this reason, SEIA is mistaken when it claims that it would be inconsistent to use distribution-system loads in the calculation of marginal distribution demand costs but then bill customers based on non-coincident demand because the non-coincident demand drives the need for the incremental distribution-system load used in the development of the marginal distribution demand costs.

SEIA does raise an important question regarding the appropriate loads to use in the marginal distribution demand cost regression analysis. As stated above, SDG&E used its distribution-system load to measure incremental distribution load for use in the marginal distribution demand cost regression analysis. However, as explained in SDG&E witness Mr. Baranowski's direct testimony, the distribution planning department performs analysis to maintain reliability of the distribution system by developing circuit and substation load forecasts to determine the capacity upgrades required on the distribution system.[51] For this reason, SDG&E recognizes that the distribution loads used in the marginal distribution demand cost regression analysis should be based on the circuit and substation load forecasts used by the distribution planning department when determining the capacity upgrade needs, instead of the actual distribution-system loads, which are not the loads the distribution planning department relied on in their capacity upgrade analysis. Attachment G presents the marginal distribution demand cost results based on SDG&E's 2002-2016 distribution planning forecasted loads. Because the distribution planning forecasted loads are considered confidential data, these loads

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[50] SDG&E Direct Testimony of John Baranowski, Chapter 5, p. JB-1.
[51] SDG&E Direct Testimony of John Baranowski, Chapter 5, pp. JB-4 through JB-7.

are not presented in my rebuttal testimony but instead are identified in my Chapter 5 marginal distribution demand cost confidential rebuttal workpaper.

F. SDG&E Proposed Updated Marginal Distribution Demand Costs

Attachment G presents the updated marginal distribution demand costs based on the distribution-system loads that reflect the adjustments to the: (a) A&G Loading Factor for O&M Non-Plant, described in Section II.B.1, (b) 2002-2016 distribution-system loads, described in Sections III.B and III.C, and (b) 2014 and 2015 feeder and local distribution and substation costs from forecasted costs to actual costs, described in Section III.C. In addition, Attachment G presents the updated marginal distribution demand costs based on the distribution planning forecasted loads that reflect the adjustments to the: (a) A&G Loading Factor for O&M Non-Plant, described in Section II.B.1, (b) 2014 and 2015 feeder and local distribution and substation costs from forecasted costs to actual costs, described in Section III.C, and (c) 2002-2016 load data to reflect distribution planning forecasted loads, described in Section III.E.

SDG&E recommends that the Commission adopt the marginal distribution demand costs based on the distribution planning forecasted loads because this analysis correctly regresses incremental distribution investments by the forecasted loads that the distribution planning department determined were necessary to meet capacity upgrade needs. Attachment A reflects SDG&E's proposed updated marginal distribution costs in this proceeding based on the distribution planning forecasted loads.

IV. SDG&E PROPOSED UPDATED DISTRIBUTION REVENUE ALLOCATION

Attachment B presents the updated EPMC distribution revenue allocation proposed by SDG&E in this rebuttal testimony based on the current distribution revenues reflected in rates effective August 1, 2016.[52] This updated EPMC distribution revenue allocation is based on the SDG&E proposed updated marginal distribution customer and marginal distribution demand costs addressed above and presented in Attachment A. Marginal distribution customer cost revenues by customer class are developed by multiplying each class' unit marginal customer cost ($/customer/year) by the forecasted number of customers in that class. The rebuttal testimony of SDG&E witness Kenneth E. Schiermeyer provides the updates to the 2016 forecasted number of customers by customer class used to calculate SDG&E's proposed updated marginal distribution customer cost revenues in this testimony.[53] Marginal distribution demand cost revenues are developed by multiplying the unit marginal feeder and local distribution costs or substation costs ($/kW/year) by each class' non-coincident demand, applicable loss factors, and each class' effective demand factors ("EDFs") at the circuit or substation level with the revenues scaled to the 2016 distribution planning forecasted loads used to develop the marginal distribution demand costs. The 2016 forecasted non-coincident demand by customer class was updated consistent with the updated 2016 forecasted kWh sales proposed in the rebuttal testimony of Mr. Schiermeyer. The rebuttal testimony of SDG&E witness Leslie Willoughby provides the proposed updates to the EDFs by customer class that are used in the calculation of the marginal distribution demand cost revenues.[54]

The sum of the marginal customer, feeder and local distribution, and substation distribution cost revenues is used to develop the distribution EPMC allocation factor. The EPMC allocation factor is then used to scale the marginal distribution class revenue allocations to equal the authorized distribution revenue requirement. SDG&E's proposed updated distribution revenue allocation by customer class is provided in Attachment B. Attachment B.1

[52] SDG&E Advice Letter 2922-E.
[53] SDG&E Rebuttal Testimony of Kenneth E. Schiermeyer, Chapter 4.
[54] SDG&E Rebuttal Testimony of Leslie Willoughby, Chapter 7.

presents the distribution marginal cost allocation factors by customer class. Attachment B.2 presents the allocation of distribution revenues to each customer class based on the distribution marginal cost allocations factors. Attachment B.3 presents the resulting distribution EPMC rates and revenues by customer class.

V. SUMMARY AND CONCLUSION

For the reasons stated above, the Commission should adopt: (a) SDG&E's proposed updated marginal distribution customer costs based on the Rental Method, as presented in Attachment A, that reflect the above described adjustments to the A&G Loading Factor for O&M Non-Plant, O&M costs to reflect the offset of $3,039,000 in 2016 forecasted Miscellaneous Revenues, and TSM RECC factors; (b) SDG&E's proposed updated marginal distribution demand costs, as presented in Attachment A, that reflect the above described adjustments to the A&G Loading Factor for O&M Non-Plant, 2014-2015 feeder and local distribution and substation costs to reflect actual costs, and 2002-2016 load data to reflect distribution planning forecasted loads; and (c) SDG&E's proposed updated distribution revenue allocations calculated based on SDG&E's proposed updated marginal distribution customer and demand costs, as described above and presented in Attachment B.

This concludes my prepared rebuttal testimony.

ATTACHMENT A

SDG&E PROPOSED UPDATED MARGINAL DISTRIBUTION COSTS

ATTACHMENT A (REBUTTAL)

SAN DIEGO GAS & ELECTRIC COMPANY ("SDG&E")
TEST YEAR ("TY") 2016 GENERAL RATE CASE ("GRC") PHASE 2, APPLICATION ("A.") 15-04-012
MARGINAL DISTRIBUTION COSTS

Proposed Distribution Marginal Unit Costs

Line No.	Description (A)		Secondary (B)	Primary (C)	Transmission (D)	Line No.
1	Customer Marginal Cost Based on Rental Method ($/Customer/Year):					1
2	Residential		$152.09			2
3	Small Commercial					3
4		0 - 5 kW	$323.57	$785.49		4
5		>5 - 20 kW	$588.70	$785.49		5
6		>20 - 50 kW	$1,232.43	$785.49		6
7		>50 kW	$1,709.43	$1,618.97		7
8		Average	$520.48	$904.55		8
9						9
10	Medium/Large Commercial & Industrial					10
11		≤500 kW	$2,272.23	$1,101.95	$7,365.07	11
12		500 - 12 MW	$5,452.08	$1,275.76	$12,851.85	12
13		> 12 MW		$1,923.27	$18,662.82	13
14		Average	$2,342.80	$1,190.27	$10,304.04	14
15						15
16	Agricultural					16
17		≤20 kW	$583.80	$918.69		17
18		>20 kW	$2,102.45	$1,054.85		18
19		Average	$989.98	$1,048.37		19
20						20
21	Lighting ($/Lamp/Year)		$11.87			21
22						22
23						23
24	Demand-Related Marginal Cost:					24
25	Feeders & Local Distribution Demand ($/kW/Year)		$60.72	$60.72		25
26						26
27	Substation Demand ($/kW/Year)		$19.67	$19.67		27
28						28
29	Total Demand-Related Marginal Cost ($/kW/Year)		$80.40	$80.40		29

Note: **Proposed Distribution Marginal Unit Costs**: the proposed distribution marginal unit costs are from the Chapter 5 Rebuttal Workpapers.

ATTACHMENT B

SDG&E PROPOSED UPDATED DISTRIBUTION REVENUE ALLOCATION

ATTACHMENT B.1 (REBUTTAL)

SAN DIEGO GAS & ELECTRIC COMPANY ("SDG&E")
TEST YEAR ("TY") 2016 GENERAL RATE CASE ("GRC") PHASE 2, APPLICATION ("A.") 15-04-012
DISTRIBUTION REVENUE ALLOCATION

Distribution Marginal Cost Allocation Factor by Customer Class

Line No.	Customer Class (A)	Customer Marginal Cost Revenue ($000) (B)	Percentage Allocation (%) (C)	Demand-Related Marginal Cost Revenue ($000) (D)	Percentage Allocation (%) (E)	Total Distribution Marginal Cost Revenue ($000) (F)	Distribution Marginal Cost Allocation Factor (%) (G)	Line No.
1	Residential	$195,733	62.77%	$189,549	40.04%	$385,282	49.07%	1
2								2
3	Small Commercial	$67,902	21.78%	$57,583	12.16%	$125,485	15.98%	3
4								4
5	Medium/Large Commercial & Industrial	$42,598	13.66%	$218,908	46.24%	$261,506	33.30%	5
6								6
7	Agricultural	$3,698	1.19%	$6,078	1.28%	$9,775	1.24%	7
8								8
9	Lighting	$1,884	0.60%	$1,310	0.28%	$3,194	0.41%	9
10								10
11	System	$311,815	100.00%	$473,427	100.00%	$785,241	100.00%	11

Note:

(1) **Distribution Marginal Cost Allocation Factors by Customer Class**: the distribution marginal cost allocation factor by customer class presented are from the Chapter 5 Rebuttal Workpapers.
(2) **Customer Marginal Cost Revenue**: reflects customer-related distribution marginal costs.
(3) **Demand-Related Marginal Cost Revenue**: reflects feeder & local distribution and substation demand-related distribution marginal costs.

ATTACHMENT B.2 (REBUTTAL)

SAN DIEGO GAS & ELECTRIC COMPANY ("SDG&E")
TEST YEAR ("TY") 2016 GENERAL RATE CASE ("GRC") PHASE 2, APPLICATION ("A.") 15-04-012
DISTRIBUTION REVENUE ALLOCATION

Distribution Revenue Allocation by Customer Class

Line No.	Customer Class (A)	Updated Distribution Revenue Allocation: Distribution Allocation Factors (%) (B)	Updated Distribution Revenue Allocation: Non Marginal Distribution Revenue ($000) (C)	Updated Distribution Revenue Allocation: Marginal Distribution Revenue ($000) (D)	Updated Distribution Revenue Allocation: Total Distribution Revenue Allocation ($000) (E)	Current Total Distribution Revenue Allocation ($000) (F)	Percentage Change (%) (G)	Line No.
1	**Residential**	49.07%		$631,459	$631,459	$618,542	2.09%	1
2								2
3	**Small Commercial**	15.98%		$205,664	$205,664	$164,775	24.82%	3
4								4
5	**Medium/Large Commercial & Industrial**	33.30%	$8,254	$428,596	$436,850	$490,116	-10.87%	5
6								6
7	**Agricultural**	1.24%		$16,021	$16,021	$17,341	-7.61%	7
8								8
9	**Lighting**	0.41%	$4,912	$5,234	$10,147	$9,366	8.33%	9
10								10
11	**System**	100.00%	$13,166	$1,286,975	$1,300,141	$1,300,141	0.00%	11
12								12
13	Distribution Revenue Requirement ($000):	$1,300,141						13
14								14
15	Non Marginal Revenue Requirement Components ($000):							15
16	Lighting Facilities Charge Revenues:	$4,912						16
17	Standby Revenues:	$5,069						17
18	Distance Adjustment Fee Revenues:	$3,185						18

Note:

(1) **Distribution Revenue Allocation by Customer Class**: the distribution revenue allocation by customer class presented are from the Chapter 5 Rebuttal Workpapers.

(2) **Updated Distribution Revenue Allocation**: allocation of the current distribution revenue requirement based on the marginal Distribution Allocation Factors presented in this Application.

(3) **Current Total Distribution Revenue Allocation**: allocation of current distribution revenue requirement based on the current class distribution allocation percentages reflected in current rates; rates . effective August 1, 2016, pursuant to SDG&E Advice Letter 2922-E.

(4) **Distribution Revenue Requirement**: the $1,300,141,000 Distribution Revenue Requirement reflects the current distribution revenues being collected in rates effective August 1, 2016, excluding revenues that have separate allocation treatment such as Self Generation Incentive Program ("SGIP"), Demand Response ("DR"), and Customer Service Initiative ("CSI") costs.

(5) **Non-Marginal Lighting Facilities Charge Revenues**: Lighting Facilities Charges of $4,912,000 are the annual lighting facilities revenues identified in the Lighting Model from SDG&E witness Christopher Swartz (Chapter 2) Workpapers.

(6) **Non-Marginal Standby Revenues**: Standby Revenues of $5,069,000 are the standby revenues based on the forecasted standby determinants multiplied by the applicable current standby rates effective August 1, 2016, pursuant to SDG&E Advice Letter 2922-E.

(7) **Non-Marginal Distance Adjustment Fee Revenues**: Distance Adjustment Fees of $3,185,000 are the annual distance adjustment fees revenues based on the forecasted overhead and underground distance adjustment fee determinants in feet multiplied by the applicable current distance adjustment fees effective August 1, 2016, pursuant to SDG&E Advice Letter 2922-E.

ATTACHMENT B.3 (REBUTTAL)

SAN DIEGO GAS & ELECTRIC COMPANY ("SDG&E")
TEST YEAR ("TY") 2016 GENERAL RATE CASE ("GRC") PHASE 2, APPLICATION ("A.") 15-04-012
DISTRIBUTION REVENUE ALLOCATION

Distribution Equal Percentage of Marginal Cost ("EPMC") Rates and Revenue by Customer Class

Line No.	Customer Class (A)	Marginal Distribution Rate (B)	EPMC Distribution Rate (C)	EPMC Distribution Revenue Allocation ($000) (D)	Line No.
1	Residential				1
2	Customer Marginal Cost ($/Customer-Month)	$12.67	$20.77		2
3	Demand-Related Marginal Cost ($/Non-Coincident kW)	$4.11	$6.74		3
4	Total - Residential			$631,459	4
5					5
6	Small Commercial				6
7	Customer Marginal Cost ($/Customer-Month)				7
8	Secondary				8
9	0 - 5 kW	$26.96	$44.19		9
10	>5 - 20 kW	$49.06	$80.40		10
11	>20 - 50 kW	$102.70	$168.32		11
12	>50 kW	$142.45	$233.47		12
13	Secondary Total	$43.34	$71.03		13
14					14
15	Primary				15
16	0 - 5 kW	$65.46	$107.28		16
17	>5 - 20 kW	$65.46	$107.28		17
18	>20 - 50 kW	$65.46	$107.28		18
19	>50 kW	$134.91	$221.12		19
20	Primary Total	$66.53	$109.04		20
21					21
22	Demand-Related Marginal Cost ($/Non-Coincident kW)				22
23	Secondary	$5.37	$8.80		23
24	Primary	$5.34	$8.75		24
25	Total	$5.37	$8.80		25
26					26
27	Total - Small Commercial			$205,664	27

SAN DIEGO GAS & ELECTRIC COMPANY ("SDG&E")
TEST YEAR ("TY") 2016 GENERAL RATE CASE ("GRC") PHASE 2, APPLICATION ("A.") 15-04-012
DISTRIBUTION REVENUE ALLOCATION

Distribution Equal Percentage of Marginal Cost ("EPMC") Rates and Revenue by Customer Class

Line No.	Customer Class (A)	Marginal Distribution Rate (B)	EPMC Distribution Rate (C)	EPMC Distribution Revenue Allocation ($000) (D)	Line No.
28					28
29	Medium/Large Commercial & Industrial				29
30					30
31	Secondary				31
32	≤500 kW	$189.35	$310.34		32
33	500 - 12 MW	$454.34	$744.64		33
34	Secondary Total	$195.58	$320.55		34
35					35
36	Primary				36
37	≤500 kW	$91.83	$150.50		37
38	500 - 12 MW	$106.31	$174.24		38
39	> 12 MW	$160.27	$262.68		39
40	Primary Total	$100.56	$164.82		40
41					41
42	Transmission				42
43	≤500 kW	$613.76	$1,005.92		43
44	500 - 12 MW	$1,070.99	$1,755.30		44
45	> 12 MW	$1,555.23	$2,548.96		45
46	Transmission Total	$962.43	$1,577.37		46
47					47
48	Demand-Related Marginal Cost ($/Non-Coincident kW)				48
49	Secondary	$8.63	$14.14		49
50	Primary	$8.58	$14.06		50
51	Total	$8.62	$14.12		51
52					52
53	Total - Medium/Large Commercial & Industrial			$428,596	53
54					54

SAN DIEGO GAS & ELECTRIC COMPANY ("SDG&E")
TEST YEAR ("TY") 2016 GENERAL RATE CASE ("GRC") PHASE 2, APPLICATION ("A.") 15-04-012
DISTRIBUTION REVENUE ALLOCATION

Distribution Equal Percentage of Marginal Cost ("EPMC") Rates and Revenue by Customer Class

Line No.	Customer Class (A)	Marginal Distribution Rate (B)	EPMC Distribution Rate (C)	EPMC Distribution Revenue Allocation ($000) (D)	Line No.
55	Agricultural				55
56	Customer Marginal Cost ($/Customer-Month)				56
57	Secondary				57
58	≤20 kW	$48.65	$79.73		58
59	>20 kW	$175.20	$287.15		59
60	Secondary Total	$78.62	$128.85		60
61					61
62	Primary				62
63	≤20 kW	$76.56	$125.47		63
64	>20 kW	$87.90	$144.07		64
65	Primary Total	$86.17	$141.24		65
66					66
67	Demand-Related Marginal Cost ($/Non-Coincident kW)				67
68	Secondary	$4.22	$6.92		68
69	Primary	$4.20	$6.88		69
70	Total	$4.22	$6.92		70
71					71
72	Total - Agricultural			$16,021	72
73					73
74	Lighting				74
75	Customer Marginal Cost ($/kWh)	$0.99	$1.62		75
76	Demand-Related Marginal Cost ($/kWh)	$5.37	$8.80		76
77	Total - Lighting			$5,234	77
78					78
79	Total-System				79
80	Customer Marginal Cost ($/Customer-Month)			$511,050	80
81	Demand-Related Marginal Cost ($/Non-Coincident kW)			$775,925	81
82	Total - System			$1,286,975	82

GRC Phase 1 Distribution Revenue Requirement:	1,300,141
Non-Marginal Revenue Requirement	13,166
Marginal Distribution Revenue Requirement Allocation	1,286,975
Marginal Customer Distribution Revenue Requirement	311,815
Marginal Demand-Related Distribution Revenue Requirement	473,427
Total Marginal Distribution Revenue Requirement	785,241
EPMC Allocation Factor	163.90%

Notes:

(1) **Distribution EPMC Rates and Revenues by Customer Class**: the distribution EPMC rates and revenues by customer class presented are from the Chapter 5 Rebuttal Workpapers.
(2) **Marginal Distribution Rate**: equals the marginal cost by class and by voltage level for demand-related margin cost divided by the class determinants.
(3) **EPMC Distribution Rate**: equals the Marginal Distribution Rate multiplied by the EPMC Distribution Allocation Factor.
(4) **EPMC Distribution Revenue Allocation**: equals the EPMC Distribution Rate multiplying by the applicable determinants.

ATTACHMENT C

REVISED A&G O&M NON-PLANT LOADING FACTOR

ATTACHMENT C (REBUTTAL)

SAN DIEGO GAS & ELECTRIC COMPANY ("SDG&E")
TEST YEAR ("TY") 2016 GENERAL RATE CASE ("GRC") PHASE 2, APPLICATION ("A.") 15-04-012
MARGINAL DISTRIBUTION CUSTOMER AND DEMAND COSTS

Revised Administrative and General ("A&G") Loading Factors for Operations & Maintenance ("O&M") Non-Plant

Line No.	Description	2009	2010	2011	2012	2013	5-Year Average
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
1	**ADMINISTRATIVE AND GENERAL EXPENSES**						
2	**(920) Administrative and General Salaries**	$14,290,294	$17,201,054	$21,679,499	$18,842,371	$24,202,412	
3	**(921) Office Supplies and Expenses**	$2,080,647	$7,655,150	$7,663,950	$9,849,366	$11,802,941	
4	**(922) Admin Expenses Transferred-Credit**	$4,725,196	$5,767,358	$7,422,656	$8,162,476	$7,659,598	
5	**(925) Injuries and Damages**	$10,774,639	$89,418,454	$163,950,485	$142,243,094	$312,716,691	
6	**(926) Employee Pensions and Benefits**	$51,996,223	$51,223,161	$59,183,873	$51,586,591	$57,170,990	
7	**(928) Regulatory Commission Expenses**	$15,627,039	$15,436,867	$14,022,098	$14,241,959	$17,713,245	
8	**(930.1) General Advertising Expenses**						
9	**(930.2) Miscellaneous General Expenses**	$17,221,322	$30,023,954	$18,584,549	$3,681,987	$4,409,948	
10							
11	**Total Non-Plant Related**	$107,264,968	$205,191,282	$277,661,798	$232,282,892	$420,356,629	
12	**(925.4) Wildfire Claims**	$0	$0	$79,279,814	$18,801,235	$215,737,954	
13	**Total Non-Plant Related Minus Wildfire Claims**	$107,264,968	$205,191,282	$198,381,984	$213,481,657	$204,618,675	
14							
15	**(923) Outside Services Employed**	$58,295,447	$60,411,738	$57,371,074	$60,418,785	$90,933,462	
16	**(924) Property Insurance**	$3,168,670	$3,646,154	$5,159,507	$7,093,526	$8,258,853	
17	**(927) Franchise Requirements**	$78,242,807	$78,596,651	$90,017,568	$91,227,453	$95,366,144	
18	**(929) Duplicate Charges-Cr.**	$1,727,837	$1,706,995	$1,860,286	$1,784,239	$1,950,344	
19	**(931) Rents**	$8,348,021	$8,606,273	$9,273,648	$10,932,665	$9,048,284	
20	**(935) Maintenance of General Plant**	$8,239,277	$7,570,736	$7,842,008	$8,639,949	$6,724,821	
21							
22	**Total Plant Related**	$154,566,385	$157,124,557	$167,803,519	$176,528,139	$208,381,220	
23							
24	**Total A&G**	$261,831,353	$362,315,839	$445,465,317	$408,811,031	$628,737,849	
25							
26	**Total O&M Expenses - Excludes Fuel Purchased Power, A&G & Water for Power**	613,857,832	553,554,697	576,219,404	633,846,596	790,175,352	
27							
28	**A&G Loading Factor Applicable to Non-Plant: Direct Testimony Proposal**	17.47%	37.07%	48.19%	36.65%	53.20%	38.51%
29							
30	**A&G Loading Factor Applicable to Non-Plant Excluding Wild Fire Claims: Rebuttal Proposal**	17.47%	37.07%	34.43%	33.68%	25.90%	$\boxed{29.71\%}$

ATTACHMENT D

REVISED TSM RECC AND PVRR FACTORS

ATTACHMENT D (REBUTTAL)

SAN DIEGO GAS & ELECTRIC COMPANY ("SDG&E")
TEST YEAR ("TY") 2016 GENERAL RATE CASE ("GRC") PHASE 2, APPLICATION ("A.") 15-04-012
MARGINAL DISTRIBUTION CUSTOMER COSTS

Revised Transformer, Services and Meter ("TSM") Real Economic Carrying Charge ("RECC") and Present Value Revenue Requirement ("PVRR") Factors

Line No.	2013 FERC Account	FERC Account Description	RECC Factors	PVRR Factors	Year-End 2013 Distribution Plant Additions	Weighted Average Factor SDG&E Direct Testimony	Weighted Average Factor UCAN Testimony	Weighted Average Factor SDG&E Rebuttal Testimony
1	**RECC Factors Used in Rental Method:**							
2	368.1	Line Transformers	9.19%		$26,220,836	49.31%	55.74%	63.05%
3	368.2	Protective Devices & Capacitors	14.99%		$5,946,023	11.18%		
4	369.1	Services Overhead	8.24%		$5,450,718	10.25%	11.59%	
5	369.2	Services Underground	8.31%		$8,635,866	16.24%	18.36%	20.76%
6	370.1	Meters	8.36%		$1,756,128	3.30%	3.73%	
7	370.2	Meter Installations	8.36%		$4,976,980	9.36%	10.58%	
8	371	Installations on Customer Premises	12.13%		$186,632	0.35%		
9	370.11	Smart Meters	11.72%		$1,756,128			4.22%
10	370.21	Meter Installations-Smart Meter	11.59%		$4,976,980			11.97%
11						100.00%	100.00%	100.00%
12	Weighted Average Customer-Related Distribution RECC (SDG&E Direct Testimony)		9.51%					
13								
14	Weighted Average Customer-Related Distribution RECC (Proposed by UCAN)		8.80%					
15	[Excludes FERC Account 368.2 and 371]							
16								
17	Weighted Average Customer-Related Distribution RECC (UCAN Proposal with SDG&E Adjustments)		9.40%					
18	[Also excludes FERC Account 369.1 and replaces 370.1 and 370.2 with 370.11 and 370.21]]							
19								
20	**SDG&E Rebuttal Proposal to Apply Individual TSM RECC Factors**							
21	**368.1**	Line Transformers		9.19%				
22	**369.2**	Services Underground		8.31%				
23								
24	**370.11**	Smart Meters		11.72%	$1,756,128			26%
25	**370.21**	Meter Installations-Smart Meter		11.59%	$4,976,980			74%
26		Weighted Average Meter RECC		11.62%				100%
27								
28								
29	**PVCC Factors Used in NCO Method:**							
30	368.1	Line Transformers		130.93%				
31	369.2	Services Underground		130.75%				
32	370.1	Meters		131.55%				
33								
34	**SDG&E Rebuttal Proposed PVCC Factors that Replace Meter PVCC with Smart Meter Average PVCC:**							
35	368.1	Line Transformers		130.93%				
36	369.2	Services Underground		130.75%				
37								
38	370.11	Smart Meters		112.99%	$1,756,128			26%
39	370.21	Meter Installations-Smart Meter		111.72%	$4,976,980			74%
40		Weighted Average Meter PVCC		112.05%				100%

ATTACHMENT E

REVISED ILLUSTRATIVE NCO METHOD CALCULATION RESULTS

ATTACHMENT E (REBUTTAL)

SAN DIEGO GAS & ELECTRIC COMPANY ("SDG&E")
TEST YEAR ("TY") 2016 GENERAL RATE CASE ("GRC") PHASE 2, APPLICATION ("A.") 15-04-012
MARGINAL DISTRIBUTION CUSTOMER COSTS

Distribution Customer Marginal Unit Cost by Customer Class Based on New Customer Only ("NCO") Method
Revised Illustrative Marginal Customer Costs --- Not Proposed by SDG&E

Line No.	Description (A)		Secondary (B)	Primary (C)	Transmission (D)	Line No.
1	Customer Marginal Cost Based on NCO Method ($/Customer/Year):					1
2	Residential		$100.27			2
3	Small Commercial					3
4		0 - 5 kW	$248.13	$488.80		4
5		>5 - 20 kW	$419.98	$488.80		5
6		>20 - 50 kW	$834.61	$488.80		6
7		>50 kW	$1,192.60	$876.88		7
8		Average	$374.17	$544.24		8
9						9
10	Medium/Large Commercial & Industrial					10
11		≤500 kW	$2,247.55	$1,104.28	$4,959.73	11
12		500 - 12 MW	$5,962.90	$1,345.30	$7,914.04	12
13		> 12 MW		$1,181.18	$11,192.54	13
14		Average	$2,323.33	$1,223.80	$6,565.82	14
15						15
16	Agricultural					16
17		≤20 kW	$428.04	$622.01		17
18		>20 kW	$1,206.77	$676.63		18
19		Average	$636.32	$674.03		19
20						20
21	Lighting ($/Lamp/Year)		$7.81			21

Note: **Distribution Customer Marginal Unit Cost by Customer Class Based on NCO Method**: the distribution customer marginal unit costs by customer class based on the NCO Method are being provided for comparison purposes, as requested by the Administrative Law Judge's rulings made at the January 26, 2016, Pre-Hearing Conference in this proceeding (A.15-04-012).

ATTACHMENT F

REVISED 2002-2016 DISTRIBUTION-SYSTEM LOADS AND 2014-2015 FEEDER & LOCAL DISTRIBUTION AND SUBSTATION COSTS

ATTACHMENT F (REBUTTAL)

SAN DIEGO GAS & ELECTRIC COMPANY ("SDG&E")
TEST YEAR ("TY") 2016 GENERAL RATE CASE ("GRC") PHASE 2, APPLICATION ("A.") 15-04-012
MARGINAL DISTRIBUTION DEMAND COSTS

Revised Distribution-System Load and Distribution Demand Costs

Line No.	Year	Load Type	System Load (MW)	Transmission Load (MW)	Distribution-System Load (System Load minus Transmission Load) (MW)
1	2002	Weather-Normalized Actual	3,803	110	3,692
2	2003	Weather-Normalized Actual	3,913	118	3,795
3	2004	Weather-Normalized Actual	4,175	124	4,051
4	2005	Weather-Normalized Actual	4,226	107	4,119
5	2006	Weather-Normalized Actual	4,403	129	4,274
6	2007	Weather-Normalized Actual	4,484	111	4,373
7	2008	Weather-Normalized Actual	4,520	155	4,365
8	2009	Weather-Normalized Actual	4,353	119	4,234
9	2010	Weather-Normalized Actual	4,265	131	4,133
10	2011	Weather-Normalized Actual	4,404	109	4,295
11	2012	Weather-Normalized Actual	4,458	123	4,335
12	2013	Weather-Normalized Actual	4,634	131	4,503
13	2014	Weather-Normalized Actual	4,371	92	4,279
14	2015	Weather-Normalized Actual	4,248	95	4,154
15	2016	Forecast	4,551	112	4,438

16			Capacity-Related	Capacity-Related
17			Feeder & Local Distribution	Substation
18	Year	Cost Type	($000)	($000)
19	2002	Actual	$28,041	$12,577
20	2003	Actual	$27,113	$3,004
21	2004	Actual	$24,253	$10,439
22	2005	Actual	$32,478	$6,586
23	2006	Actual	$28,284	$5,097
24	2007	Actual	$36,326	$6,896
25	2008	Actual	$28,167	$4,816
26	2009	Actual	$29,540	$7,883
27	2010	Actual	$29,337	$8,613
28	2011	Actual	$25,164	$11,339
29	2012	Actual	$31,455	$4,065
30	2013	Actual	$28,962	$8,563
31	2014	Actual	$34,135	$13,819
32	2015	Actual	$47,554	$3,247
33	2016	Forecast	$67,855	$7,264

ATTACHMENT G

COMPARISON OF MARGINAL DISTRIBUTION DEMAND COSTS BASED ON DISTRIBUTION-SYSTEM LOADS VERSUS DISTRIBUTION PLANNING FORECASTED LOADS

ATTACHMENT G (REBUTTAL)

SAN DIEGO GAS & ELECTRIC COMPANY ("SDG&E")
TEST YEAR ("TY") 2016 GENERAL RATE CASE ("GRC") PHASE 2, APPLICATION ("A.") 15-04-012
MARGINAL DISTRIBUTION DEMAND COSTS

Comparison of Marginal Distribution Demand Costs Based on Distribution-System Loads versus Distribution Planning Forecasted Loads

Line No.	Marginal Distribution Demand Costs Based on Updated Distribution-System Loads:	
1	Feeder & Local Distribution Demand Costs ($/kW-Year)	$75.68
2		
3	Substation Demand Costs ($/kW-Year)	$19.45

4	Marginal Distribution Demand Costs Based on Distribution Planning Forecast Loads:	
5		
6	Feeder & Local Distribution Demand Costs ($/kW-Year)	$60.72
7		
8	Substation Demand Costs ($/kW-Year)	$19.67

<u>FIXED COST REPORT - ATTACHMENT C</u>

SDG&E 2016 GRC PHASE 2 MARGINAL COMMODITY COSTS

DIRECT TESTIMONY

Application of SAN DIEGO GAS & ELECTRIC COMPANY (U 902 E) For Authority To Update Marginal Costs, Cost Allocation, And Electric Rate Design.

Application: 15-04-012
Exhibit No.: SDG&E-07

PREPARED DIRECT TESTIMONY OF

JEFFREY J. SHAUGHNESSY

ON BEHALF OF SAN DIEGO GAS & ELECTRIC COMPANY IN

SUPPORT OF SECOND AMENDED APPLICATION

CHAPTER 7

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF CALIFORNIA

February 9, 2016

#301913

TABLE OF CONTENTS

PREPARED DIRECT TESTIMONY OF

JEFFREY J. SHAUGHNESSY IN SUPPORT OF SECOND AMENDED APPLICATION

CHAPTER 7

I. PURPOSE AND OVERVIEW

The purpose of this testimony is to provide the marginal cost basis for the development of commodity rates as well as the cost basis for the allocation of commodity costs and Ongoing Competition Transition Charge ("CTC") costs to the customer classes. Marginal commodity costs are the incremental electric commodity costs incurred on behalf of utility customers, and are composed of marginal energy costs and marginal generation capacity costs. Marginal energy costs ("MEC") are the added energy costs incurred to meet electricity consumption. Marginal generation capacity costs ("MGCC") relate to the added costs incurred to meet electric demand. San Diego Gas & Electric Company ("SDG&E") is proposing in this General Rate Case ("GRC") Phase 2 Application to allocate costs to reflect the marginal commodity costs developed herein.

My testimony is organized as follows:

Section II – Proposed Change to Time of Use ("TOU") Periods: SDG&E proposes a change to the time of use period definitions in Chapter 1, the Testimony of SDG&E witness Cynthia Fang. All calculations included herein show results with SDG&E's proposed time of use period definitions.

Section III – Calculation of Marginal Energy Costs: MEC are the projected energy costs incurred to meet electricity consumption. Since SDG&E transacts in the California Independent System Operator ("CAISO") markets, the marginal energy costs are based on monthly electric forward market prices specific to South Path-15 ("SP-15") and an annual hourly profile of electricity prices representative of the San Diego area. A Renewable Portfolio

Standard ("RPS") adder is also included since added load requires added renewable energy under the RPS.

Section IV – Calculation of Marginal Generation Capacity Costs: MGCC relate to the added costs incurred to meet electric demand. MGCC are calculated based on long-term considerations and are based on the net cost of new entry of a combustion turbine ("CT"), the long-term cost of adding new capacity. This amount is equal to the fixed costs of a CT less expected profits from energy and ancillary service markets.

Section V – Commodity Revenue Allocation: presents the proposal to use marginal costs coupled with the Equal Percent of Marginal Costs ("EPMC") methodology to allocate the authorized commodity revenue requirement to each customer class based on the calculated MEC and MGCC in Sections III and IV.

Section VI – CTC Revenue Allocation: presents an updated allocation for CTC revenues.

Section VII – Summary and Conclusion: provides a summary of recommendations.

Section VIII - Statement of Qualifications: presents my qualifications.

My testimony also contains the following:

- **Appendix – Glossary of Acronyms**
- **Attachment A – Commodity Marginal Costs**
- **Attachment B – Commodity Revenue Allocations**
- **Attachment C – CTC Revenue Allocations**
- **Attachment D – Summary of Updates from April Filing**

II. PROPOSED CHANGE TO TIME OF USE PERIODS

SDG&E proposes a change to the TOU period definitions addressed in Chapter 1. Table JJS-1 presents the currently authorized standard TOU periods[1] and proposed TOU periods.

Table JJS-1

Current Standard Time-of-use Periods		Proposed Time-of-use Periods	
Summer on-peak	11am - 6pm non-holiday weekdays	**On-peak**	4pm - 9pm daily
Winter on-peak	5pm - 8pm non-holiday weekdays		
Off-peak	12am - 6am & 10pm-12am non-holiday weekdays and all weekends/holidays	**Super off-peak**	12am - 6am non-holiday weekdays and 12am - 2pm weekends/holidays
Semi-peak	All other times	**Off-peak**	All other times

This testimony presents updated marginal commodity cost calculations and updated commodity revenue allocations that reflect SDG&E's proposed time of use period definitions.

III. CALCULATION OF MARGINAL ENERGY COSTS

MEC reflect expected future energy market conditions to assess future hourly electricity prices. Since the goal is to forecast future hourly prices, SDG&E used a forecasted hourly profile for 2016 based upon net demand in the SP-15 market[2] and projected monthly on-peak and off-peak 2016 SP-15 electric market forward market prices. The result is a profile of hourly electricity prices for calendar year 2016. The prices in SP-15 are used since SDG&E's load is in the SP-15 market area and forward prices are available for SP-15.

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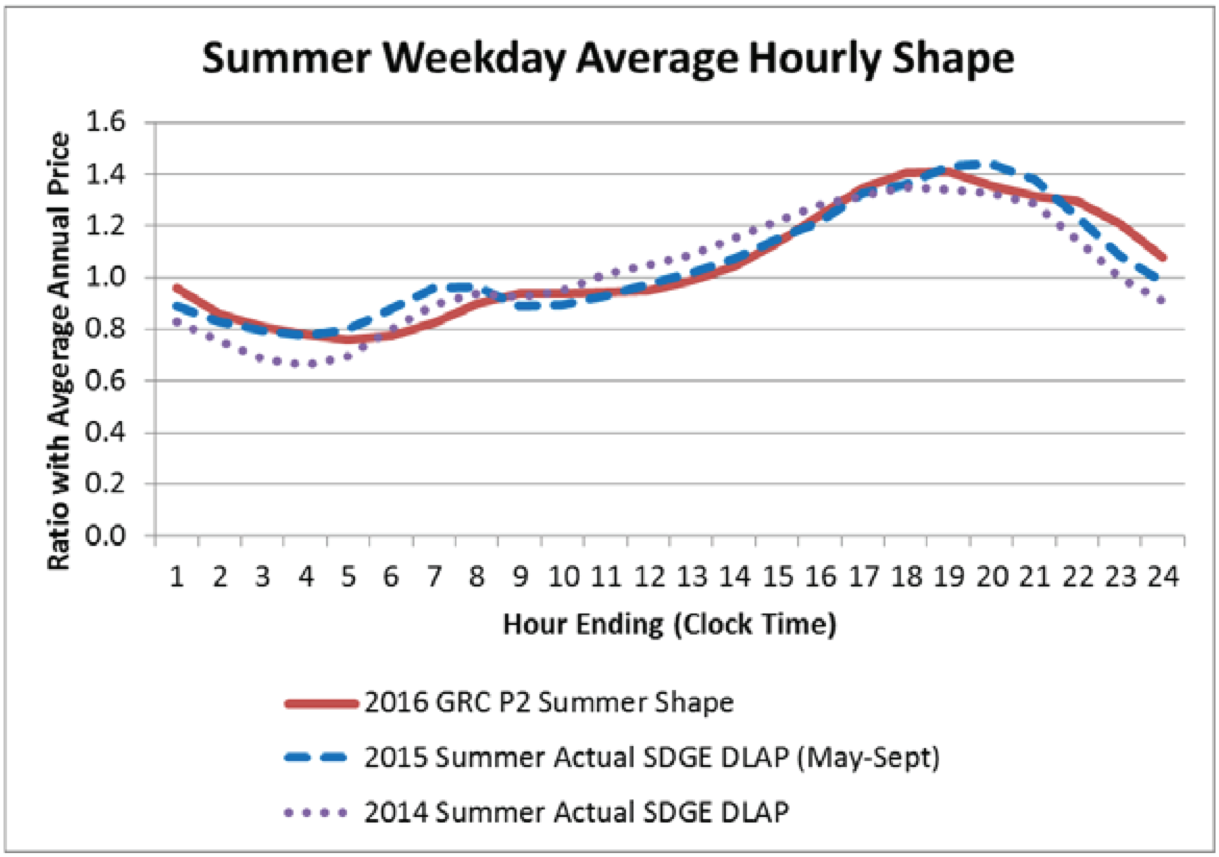
[1] SDG&E currently offers several optional residential rate schedules with different TOU period definitions. As described in the direct testimony of Ms. Fang, SDG&E proposes one TOU period definition for all rate schedules.

[2] The hourly price profile was developed and used in SDG&E's 2015 and 2016 Energy Resource Recovery Account ("ERRA") Forecast Proceedings (A.14-04-015 and A.15-04-014)

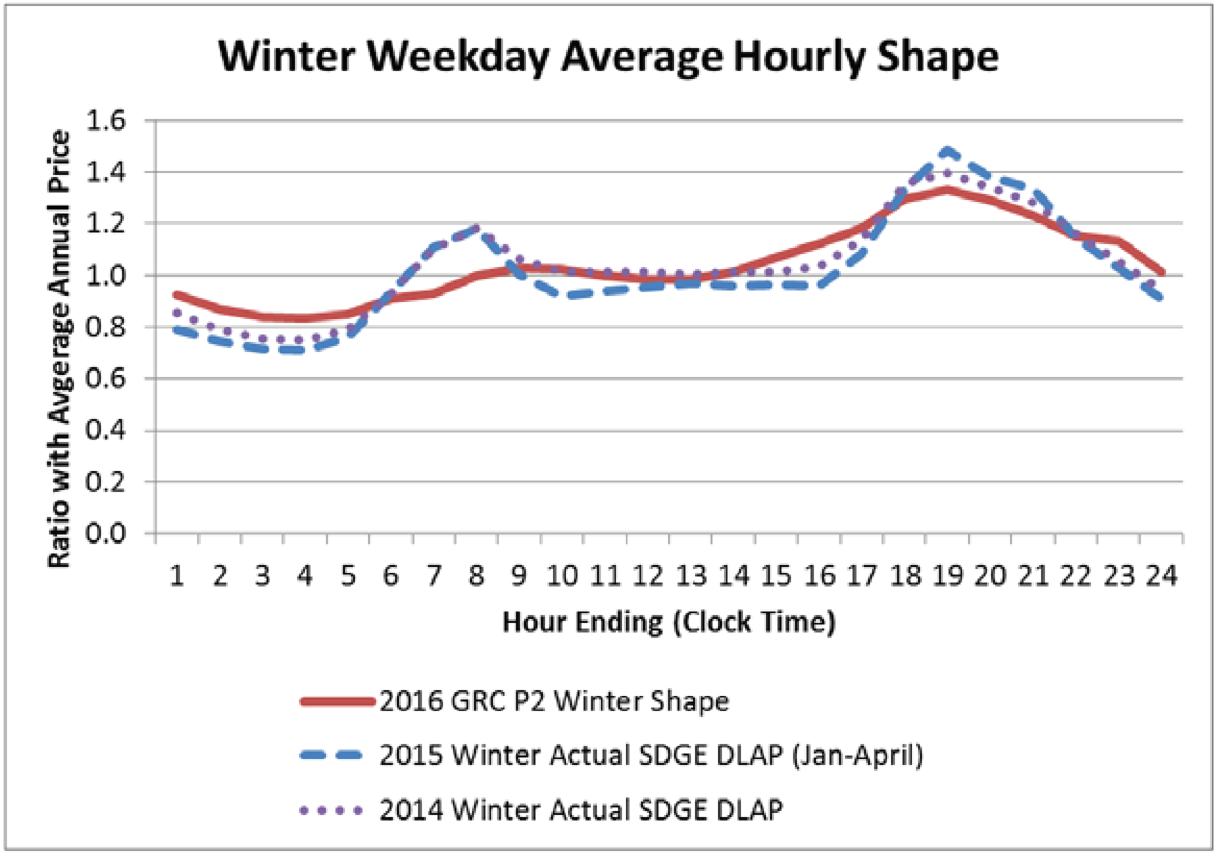
The SDG&E forecasted 2016 hourly price shape, based on SP-15, is illustrated in Chart JJS-1 and Chart JJS-2 for the average summer and winter non-holiday weekdays, compared to the actual SDG&E Default Load Aggregation Point ("DLAP") prices observed in 2014 and 2015 through September, which is 4 summer months and 4 winter months.[3]

Chart JJS-1: Summer Weekday Hourly Shape



[3] Locational Marginal Prices ("LMP"), From 01/01/2014 To 09/30/2015, Market: DAM, Node: DLAP_SDGE-APND http://oasis.caiso.com/. Note that these prices are not weather adjusted.

Chart JJS-2: Winter Weekday Hourly Shape



For the development of the average hourly prices, the monthly on-peak and off-peak forward prices are multiplied by the monthly on-peak and off-peak hourly demand profiles to arrive at hourly prices. The hourly prices are then aggregated by the appropriate time periods to develop the TOU marginal energy prices. The resulting MEC ratios with the annual average price by proposed TOU period are shown in Table JJS-2. The average annual price is calculated to be $32.38 per MWh, or 3.238 cents per kWh.

Table JJS-2: MEC Factors and Prices by TOU Period

Proposed TOU Periods					
	MEC Factors			MEC Cents per kWh	
	Summer	Winter	x Average	Summer	Winter
On-Peak	1.295	1.210	Annual Price	4.193	3.917
Off-Peak	1.032	1.024	(3.238	3.342	3.316
Super Off-Peak	0.789	0.843	¢/kWh)	2.554	2.729

The SP-15 forward prices represent the wholesale cost of energy in 2016. But, incremental energy will not be entirely purchased from the wholesale market because of California's 33 percent RPS mandate. Twenty-five percent of incremental energy in 2016 will be renewables pursuant to legislation.[4] In order to capture the full marginal cost of energy, an RPS premium is added to the wholesale energy prices after they are grouped by TOU period. The RPS premium is defined as the "Green Value," calculated by the California Public Utilities Commission's ("Commission") Energy Division, minus the average annual SP-15 energy price, then multiplied by the RPS Target for 2016 of 25%; ($0.079131/kWh – $0.03238/kWh) x 25% = $0.01144/kWh. The RPS adder is a single value for all hours of the year, as the RPS requirement is yearly (i.e. it's a % of yearly energy sales). The resulting total MEC by TOU period are shown in Table JJS-3.

[4] Established in 2002 under Senate Bill 1078, accelerated in 2006 under Senate Bill 107 and expanded in 2011 under Senate Bill 2.

Table JJS-3: Total Marginal Energy Prices

Proposed TOU Periods	Wholesale (¢/kWh)	RPS Adder (¢/kWh)	Total (¢/kWh)
Summer (May 1 - October 31)			
On-peak : 4pm - 9pm daily	4.193	1.144	5.337
Off-peak: All other hours	3.342	1.144	4.486
Super off-peak: 12am - 6am non-holiday weekdays and 12am - 2pm weekends/holidays	2.554	1.144	3.698
Winter (November 1 - April 30)			
On-peak: 4pm - 9pm daily	3.917	1.144	5.061
Off-peak : All other hours	3.316	1.144	4.460
Super off-peak: 12am - 6am non-holiday weekdays and 12am - 2pm weekends/holidays	2.729	1.144	3.873
	RPS Premium	4.575	
	RPS %	25%	

These total marginal energy costs shown in Table JJS-3 above are input values for the commodity cost allocation to customer classes presented in Section V.

IV. CALCULATION OF MARGINAL GENERATION CAPACITY COSTS

The methodology employed by SDG&E in calculating MGCC can be viewed as a net cost of new entry approach. MGCC answers the question: What price would be required to incent a new generator to enter the market and sell firm capacity? The answer is calculated based on the cost of building the facility less anticipated revenues from California's energy markets. SDG&E computes MGCC by calculating the cost of building a new CT including all permitting, financing, and development costs and deducting expected earnings in California energy and ancillary service markets. SDG&E uses publicly available information to provide a transparent calculation.

To estimate a CT's fixed cost, SDG&E uses the installed cost for a CT addition, $1,316/kW, and fixed and variable Operations & Maintenance ("O&M") from the California Energy Commission's ("CEC") Estimated Cost of New Renewable and Fossil Generation in California Report, CEC-200-2014-003-SD.[5] The installed cost is converted to a short-term annual cost using a real economic carrying charge approach ("RECC"), and then fixed O&M and various loaders are added.[6] Finally, the cost is escalated to 2016 dollars using escalators developed in SDG&E's 2016 GRC Phase 1.[7]

To calculate the net cost of capacity, projected market earnings from California's energy and ancillary service markets are deducted from the annualized cost of a CT. SDG&E uses a 4-year average of the SP-15 energy revenues minus operating costs as the market earnings and SP-15 ancillary service revenue from the CAISO Department of Market Monitoring Annual Report on Market Issues & Performance.[8] The resulting MGCC calculation is shown in Table JJS-4.

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[5] Tables 59 and 60 CEC Estimated Cost of New Renewable and Fossil Generation in California, March 2015.

[6] SDG&E RECC factors include property tax in the RECC factor.

[7] A.14-11-003, Ex. SDG&E-33, Direct Testimony of Scott R. Wilder, p. SRW-5 at Table SDG&E-SRW-2: Summary of Cost Escalation Indexes.

[8] Table 1.9 *Financial analysis of new combustion turbine (2011-2014)* 2014 Annual Report on Market Issues & Performance, California ISO Department of Market Monitoring, June 2015.

Table JJS-4: MGCC

Marginal Generation Capacity Cost	
	2016 $/kW-Yr
Short-term Marginal Cost of a Combustion Turbine	$165.29
Less Energy Market Earnings	$43.69
Less Ancillary Service Market Earnings	$3.44
Marginal Generation Capacity Costs	$118.16

The MGCC is an input for the commodity cost allocation to customer classes presented in Section V.

SDG&E used Loss of Load Expectation ("LOLE") results presented in Chapter 3, the direct testimony of SDG&E witness Robert Anderson for generation capacity cost allocation. This LOLE approach is an accepted methodology to allocate generation capacity needs to months, day, and hours.[9] The use of the top 100 hours is consistent with the past SDG&E approach in the GRC Phase 2.[10] The LOLE approach was also used in SDG&E's 2015 Rate Design Window ("RDW").[11] SDG&E proposes to continue basing commodity capacity allocation on the top 100 hours of forecasted need. SDG&E allocated capacity to seasons, days (weekdays/weekends), hours and TOU periods as shown in Table JJS-5.

[9] A.14-01-027, Chapter 3 Direct Testimony of D. Barker and 2013 California Net Energy Metering Ratepayer Impacts Evaluation prepared for the California Public Utilities Commission, by Energy and Environmental Economics ("E3").

[10] A.11-10-002, SDG&E 2012 General Rate Case Phase II Chapter 3 Second Revised Testimony of William G. Saxe.

[11] A.14-01-027, SDG&E 2015 Rate Design Window Filing Chapter 3 Prepared Direct Testimony of David T. Barker.

Table JJS-5: Top 100 Hour Loss of Load Expectation

LOLE % by TOU Period		
Proposed TOU Periods	**Summer**	**Winter**
On-peak : 4pm - 9pm daily	76.7%	0.0%
Off-peak: All other hours	23.3%	0.0%
Super off-peak: 12am - 6am non-holiday weekdays and 12am - 2pm weekends/holidays	0.0%	0.0%
Total	100.0%	0.0%

V. COMMODITY REVENUE ALLOCATION

SDG&E proposes no change to the current methodology to use the EPMC revenue allocation methodology to allocate the authorized commodity revenue requirement to customer classes.

Under SDG&E's commodity revenue allocation proposal, the authorized commodity revenue requirement is allocated among customer classes based on the proposed marginal generation capacity and energy revenue cost responsibilities by customer class. The unit marginal generation capacity and energy costs, presented in Sections III and IV above, are multiplied by the appropriate cost drivers to develop the marginal commodity revenue allocations by customer class.

Marginal energy cost revenues by customer class are developed by multiplying the applicable marginal energy prices ($/kWh) by the 2016 forecasted TOU energy usage in each TOU period for each customer class.

Marginal capacity cost revenues by customer class are developed by multiplying the unit marginal generation capacity cost ($/kW/year) by each class' estimated contribution to total bundled load based on the top 100 hours with the highest expected need for new resources, described in section IV above.

The sum of the resulting marginal generation capacity and energy revenues are used to determine the commodity EPMC allocation factor, defined as the commodity revenue requirement divided by the commodity marginal cost revenues. The EPMC allocation factor is then used to scale the commodity marginal cost revenues to ensure that the sum equals the authorized commodity revenue requirement. The EPMC rates and resulting commodity class allocations are shown in Attachment A and Attachment B, respectively.

VI. CTC REVENUE ALLOCATION

CTC revenues are also allocated based on the "Top 100 hours" allocation methodology, as adopted by the Commission in D.00-06-034. In this proceeding, SDG&E does not propose to change the allocation methodology. Instead, SDG&E merely proposes to update the top 100 hour data for the more recent 3 years available, 2009-2011, used to allocate the CTC revenue requirement. The "Top 100 hours" methodology allocates revenues based on the customer classes' contribution to the top 100 hours of system load during a given annual period. The resulting CTC class allocations are shown in Attachment C.

VII. SUMMARY AND CONCLUSION

For the foregoing reasons, the marginal commodity costs presented herein as well as the proposal to use the EPMC revenue allocation methodology to allocate the authorized commodity revenue requirement to customer classes are reasonable and should be adopted. In addition, SDG&E recommends that the Commission adopt its proposal to update the data used to allocate the CTC authorized revenue requirement under the current “Top 100 hours” allocation methodology.

This concludes my prepared direct testimony.

VIII. WITNESS QUALIFICATIONS

My name is Jeffrey J. Shaughnessy. My business address is 8330 Century Park Court, San Diego, California 92123.

I have been employed as a Project Manager in the Rate Strategy & Analysis group in the Customer Pricing Department of San Diego Gas & Electric Company since 2014. My primary responsibilities include the development of cost-of-service studies, determination of revenue allocation, and support of electric rate design in various regulatory filings. I began work at SDG&E in 2011 as a Business Analyst and have held positions of increasing responsibility in the Electric Rates group.

I received a Bachelor of Arts in Finance from Michigan State University in 2007 and a Master of Arts in Economics from San Diego State University in 2011.

I have previously submitted testimony before the Federal Energy Regulatory Commission.

APPENDIX – GLOSSARY OF ACRONYMS

CAISO	California Independent System Operator
CEC	California Energy Commission
Commission	California Public Utilities Commission
CT	Combustion Turbine
CTC	Competition Transition Charge
DLAP	Default Load Aggregation Point
E3	Energy and Environmental Economics
EPMC	Equal Percent of Marginal Costs
ERRA	Energy Resource Recovery Account
GRC	General Rate Case
LMP	Locational Marginal Prices
LOLE	Loss of Load Expectation
MEC	Marginal Energy Costs
MGCC	Marginal Generation Capacity Costs
O&M	Operations & Maintenance
RDW	Rate Design Window
RECC	Real Economic Carrying Charge
RPS	Renewable Portfolio Standard
SDG&E	San Diego Gas & Electric Company
SP-15	South Path-15
TOU	Time of Use

ATTACHMENT A

Commodity Marginal Costs

ATTACHMENT A

SAN DIEGO GAS & ELECTRIC COMPANY
2016 GENERAL RATE CASE (GRC) PHASE 2 - APPLICATION 15-04-012
ELECTRIC COMMODITY MARGINAL COSTS AND EPMC RATES & REVENUES, PROPOSED TOU - CHAPTER 7 (SHAUGHNESSY)

Line No.	Description (A)	Unit (B)	Marginal Energy Rate w/ losses (C)	Marginal Capacity Rate w/ losses (D)	Marginal Energy Rate Revenue (E)	Marginal Capacity Rate Revenue (F)	Total Marginal Rate Revenue (G)	EPMC Energy Rate (H)	EPMC Capacity Rate (I)	EPMC Energy Rate Revenue (J)	EPMC Capacity Rate Revenue (K)	Total EPMC Rate Revenue (L)	Line No.
1	**RESIDENTIAL**				$346,155,336	$201,161,113	$547,316,449			$567,085,982	$329,550,453	$896,636,434	1
2	*Secondary*												2
3	**Summer**												3
4	On-Peak Demand	$/kW	0.00	7.25				0.00	11.88				4
5	On-Peak Energy	$/kWh	0.05659	0.00000				0.09271	0.00000				5
6	Off-Peak Energy	$/kWh	0.04753	0.02504				0.07787	0.04103				6
7	Super Off-Peak Energy	$/kWh	0.03891	0.00000				0.06375	0.00000				7
8													8
9	**Winter**												9
10	On-Peak Demand	$/kW	0.00	0.00				0.00	0.00				10
11	On-Peak Energy	$/kWh	0.05361	0.00000				0.08782	0.00000				11
12	Off-Peak Energy	$/kWh	0.04713	0.00000				0.07722	0.00000				12
13	Super Off-Peak Energy	$/kWh	0.04074	0.00000				0.06675	0.00000				13
14													14
15	**SMALL COMMERCIAL**				$93,369,698	$39,534,912	$132,904,610			$152,962,099	$64,767,727	$217,729,826	15
16	*Secondary*												16
17	**Summer**												17
18	On-Peak Demand	$/kW	0.00	6.68				0.00	10.95				18
19	On-Peak Energy	$/kWh	0.05659	0.00000				0.09271	0.00000				19
20	Off-Peak Energy	$/kWh	0.04753	0.02201				0.07787	0.03606				20
21	Super Off-Peak Energy	$/kWh	0.03891	0.00000				0.06375	0.00000				21
22													22
23	**Winter**												23
24	On-Peak Demand	$/kW	0.00	0.00				0.00	0.00				24
25	On-Peak Energy	$/kWh	0.05361	0.00000				0.08782	0.00000				25
26	Off-Peak Energy	$/kWh	0.04713	0.00000				0.07722	0.00000				26
27	Super Off-Peak Energy	$/kWh	0.04074	0.00000				0.06675	0.00000				27
28													28
29	*Primary*												29
30	**Summer**												30
31	On-Peak Demand	$/kW	0.00	6.65				0.00	10.89				31
32	On-Peak Energy	$/kWh	0.05632	0.00000				0.09227	0.00000				32
33	Off-Peak Energy	$/kWh	0.04731	0.02191				0.07751	0.03589				33
34	Super Off-Peak Energy	$/kWh	0.03879	0.00000				0.06355	0.00000				34
35													35
36	**Winter**												36
37	On-Peak Demand	$/kW	0.00	0.00				0.00	0.00				37
38	On-Peak Energy	$/kWh	0.05336	0.00000				0.08742	0.00000				38
39	Off-Peak Energy	$/kWh	0.04694	0.00000				0.07690	0.00000				39
40	Super Off-Peak Energy	$/kWh	0.04062	0.00000				0.06655	0.00000				40

ATTACHMENT A

SAN DIEGO GAS & ELECTRIC COMPANY
2016 GENERAL RATE CASE (GRC) PHASE 2 - APPLICATION 15-04-012
ELECTRIC COMMODITY MARGINAL COSTS AND EPMC RATES & REVENUES, PROPOSED TOU - CHAPTER 7 (SHAUGHNESSY)

Line No.	Description (A)	Unit (B)	Marginal Energy Rate w/ losses (C)	Marginal Capacity Rate w/ losses (D)	Marginal Energy Rate Revenue (E)	Marginal Capacity Rate Revenue (F)	Total Marginal Rate Revenue (G)	EPMC Energy Rate (H)	EPMC Capacity Rate (I)	EPMC Energy Rate Revenue (J)	EPMC Capacity Rate Revenue (K)	Total EPMC Rate Revenue (L)	Line No.
1	**MEDIUM & LARGE COMMERCIAL/INDUSTRIAL**				$298,190,930	$121,312,703	$419,503,633			$488,508,710	$198,739,485	$687,248,195	1
2	*Secondary*												2
3	**Summer**												3
4	On-Peak Demand	$/kW	0.00	10.24				0.00	16.77				4
5	On-Peak Energy	$/kWh	0.05659	0.00000				0.09271	0.00000				5
6	Off-Peak Energy	$/kWh	0.04753	0.01984				0.07787	0.03251				6
7	Super Off-Peak Energy	$/kWh	0.03891	0.00000				0.06375	0.00000				7
8													8
9	**Winter**												9
10	On-Peak Demand	$/kW	0.00	0.00				0.00	0.00				10
11	On-Peak Energy	$/kWh	0.05361	0.00000				0.08782	0.00000				11
12	Off-Peak Energy	$/kWh	0.04713	0.00000				0.07722	0.00000				12
13	Super Off-Peak Energy	$/kWh	0.04074	0.00000				0.06675	0.00000				13
14													14
15	*Primary*												15
16	**Summer**												16
17	On-Peak Demand	$/kW	0.00	10.19				0.00	16.69				17
18	On-Peak Energy	$/kWh	0.05632	0.00000				0.09227	0.00000				18
19	Off-Peak Energy	$/kWh	0.04731	0.01975				0.07751	0.03236				19
20	Super Off-Peak Energy	$/kWh	0.03879	0.00000				0.06355	0.00000				20
21													21
22	**Winter**												22
23	On-Peak Demand	$/kW	0.00	0.00				0.00	0.00				23
24	On-Peak Energy	$/kWh	0.05336	0.00000				0.08742	0.00000				24
25	Off-Peak Energy	$/kWh	0.04694	0.00000				0.07690	0.00000				25
26	Super Off-Peak Energy	$/kWh	0.04062	0.00000				0.06655	0.00000				26
27													27
28	*Transmission*												28
29	**Summer**												29
30	On-Peak Demand	$/kW	0.00	9.76				0.00	15.98				30
31	On-Peak Energy	$/kWh	0.05392	0.00000				0.08834	0.00000				31
32	Off-Peak Energy	$/kWh	0.04531	0.01892				0.07423	0.03099				32
33	Super Off-Peak Energy	$/kWh	0.03723	0.00000				0.06100	0.00000				33
34													34
35	**Winter**												35
36	On-Peak Demand	$/kW	0.00	0.00				0.00	0.00				36
37	On-Peak Energy	$/kWh	0.05111	0.00000				0.08374	0.00000				37
38	Off-Peak Energy	$/kWh	0.04501	0.00000				0.07373	0.00000				38
39	Super Off-Peak Energy	$/kWh	0.03899	0.00000				0.06387	0.00000				39

ATTACHMENT A

SAN DIEGO GAS & ELECTRIC COMPANY
2016 GENERAL RATE CASE (GRC) PHASE 2 - APPLICATION 15-04-012
ELECTRIC COMMODITY MARGINAL COSTS AND EPMC RATES & REVENUES, PROPOSED TOU - CHAPTER 7 (SHAUGHNESSY)

Line No.	Description (A)	Unit (B)	Marginal Energy Rate w/ losses (C)	Marginal Capacity Rate w/ losses (D)	Marginal Energy Rate Revenue (E)	Marginal Capacity Rate Revenue (F)	Total Marginal Rate Revenue (G)	EPMC Energy Rate (H)	EPMC Capacity Rate (I)	EPMC Energy Rate Revenue (J)	EPMC Capacity Rate Revenue (K)	Total EPMC Rate Revenue (L)	Line No.
1	**AGRICULTURE**				$13,840,284	$4,594,612	$18,434,896			$22,673,726	$7,527,084	$30,200,809	1
2	*Secondary*												2
3	**Summer**												3
4	On-Peak Demand	$/kW	0.00	5.63				0.00	9.23				4
5	On-Peak Energy	$/kWh	0.05659	0.00000				0.09271	0.00000				5
6	Off-Peak Energy	$/kWh	0.04753	0.01327				0.07787	0.02174				6
7	Super Off-Peak Energy	$/kWh	0.03891	0.00000				0.06375	0.00000				7
8													8
9	**Winter**												9
10	On-Peak Demand	$/kW	0.00	0.00				0.00	0.00				10
11	On-Peak Energy	$/kWh	0.05361	0.00000				0.08782	0.00000				11
12	Off-Peak Energy	$/kWh	0.04713	0.00000				0.07722	0.00000				12
13	Super Off-Peak Energy	$/kWh	0.04074	0.00000				0.06675	0.00000				13
14													14
15	*Primary*												15
16	**Summer**												16
17	On-Peak Demand	$/kW	0.00	5.61				0.00	9.19				17
18	On-Peak Energy	$/kWh	0.05632	0.00000				0.09227	0.00000				18
19	Off-Peak Energy	$/kWh	0.04731	0.01321				0.07751	0.02164				19
20	Super Off-Peak Energy	$/kWh	0.03879	0.00000				0.06355	0.00000				20
21													21
22	**Winter**												22
23	On-Peak Demand	$/kW	0.00	0.00				0.00	0.00				23
24	On-Peak Energy	$/kWh	0.05336	0.00000				0.08742	0.00000				24
25	Off-Peak Energy	$/kWh	0.04694	0.00000				0.07690	0.00000				25
26	Super Off-Peak Energy	$/kWh	0.04062	0.00000				0.06655	0.00000				26
27													27
28	**LIGHTING**				$4,137,271	$1,330,067	$5,467,338			$6,777,848	$2,178,971	$8,956,819	28
29	*Secondary*												29
30	**Summer**												30
31	On-Peak Demand	$/kW	0.00	9.33				0.00	15.29				31
32	On-Peak Energy	$/kWh	0.05659	0.00000				0.09271	0.00000				32
33	Off-Peak Energy	$/kWh	0.04753	0.01024				0.07787	0.01677				33
34	Super Off-Peak Energy	$/kWh	0.03891	0.00000				0.06375	0.00000				34
35													35
36	**Winter**												36
37	On-Peak Demand	$/kW	0.00	0.00				0.00	0.00				37
38	On-Peak Energy	$/kWh	0.05361	0.00000				0.08782	0.00000				38
39	Off-Peak Energy	$/kWh	0.04713	0.00000				0.07722	0.00000				39
40	Super Off-Peak Energy	$/kWh	0.04074	0.00000				0.06675	0.00000				40
41													41
42	**TOTAL RATE REVENUE SUMMARY**												42
43													43
44	**RESIDENTIAL**				$346,155,336	$201,161,113	$547,316,449			$567,085,982	$329,550,453	$896,636,434	44
45	**SMALL COMMERCIAL**				$93,369,698	$39,534,912	$132,904,610			$152,962,099	$64,767,727	$217,729,826	45
46	**MEDIUM/LARGE C&I**				$298,190,930	$121,312,703	$419,503,633			$488,508,710	$198,739,485	$687,248,195	46
47	**AGRICULTURAL**				$13,840,284	$4,594,612	$18,434,896			$22,673,726	$7,527,084	$30,200,809	47
48	**LIGHTING**				$4,137,271	$1,330,067	$5,467,338			$6,777,848	$2,178,971	$8,956,819	48
49	**TOTAL**				$755,693,519	$367,933,407	$1,123,626,926			$1,238,008,364	$602,763,719	$1,840,772,084	49

ATTACHMENT B

Commodity Revenue Allocations

ATTACHMENT B.1

SAN DIEGO GAS & ELECTRIC COMPANY
2016 GENERAL RATE CASE (GRC) PHASE 2 - APPLICATION 15-04-012
ELECTRIC COMMODITY REVENUE ALLOCATION - CHAPTER 7 (SHAUGHNESSY)

Commodity Marginal Cost Allocation by Customer Class

		PROPOSED GRC P2 (PROPOSED TOU)				
		MARGINAL ENERGY COSTS		MARGINAL CAPACITY COSTS		
Line No.	Customer Class (A)	% Allocation (B)	$ Allocation (C)	% Allocation (D)	$ Allocation (E)	Line No.
1	RESIDENTIAL	45.81%	$346,155,336	54.67%	$201,161,113	1
2	SMALL COMMERCIAL	12.36%	$93,369,698	10.75%	$39,534,912	2
3	MEDIUM/LARGE C&I	39.46%	$298,190,930	32.97%	$121,312,703	3
4	AGRICULTURAL	1.83%	$13,840,284	1.25%	$4,594,612	4
5	LIGHTING	0.55%	$4,137,271	0.36%	$1,330,067	5
6	TOTAL	100.00%	$755,693,519	100.00%	$367,933,407	6

ATTACHMENT B.2

SAN DIEGO GAS & ELECTRIC COMPANY
2016 GENERAL RATE CASE (GRC) PHASE 2 - APPLICATION 15-04-012
ELECTRIC COMMODITY REVENUE ALLOCATION - CHAPTER 7 (SHAUGHNESSY)

Commodity Allocation by Customer Class

		CURRENT (11/1/2015)		PROPOSED GRC P2 (PROPOSED TOU)				
Line No.	Customer Class (A)	% Allocation (B)	$ Allocation (C)	% Allocation (D)	$ Allocation (E)	$ Change (F)	% Change (G)	Line No.
1	RESIDENTIAL	45.69%	$841,005,102	48.71%	$896,636,434	$55,631,333	6.61%	1
2	SMALL COMMERCIAL	11.34%	$208,679,888	11.83%	$217,729,826	$9,049,938	4.34%	2
3	MEDIUM/LARGE C&I	41.02%	$755,115,446	37.33%	$687,248,195	-$67,867,251	-8.99%	3
4	AGRICULTURAL	1.53%	$28,163,472	1.64%	$30,200,809	$2,037,338	7.23%	4
5	LIGHTING	0.42%	$7,808,176	0.49%	$8,956,819	$1,148,643	14.71%	5
6	TOTAL	100.00%	$1,840,772,084	100.00%	$1,840,772,084	$0	0.00%	6

ATTACHMENT C

CTC Class Allocations

ATTACHMENT C

SAN DIEGO GAS & ELECTRIC COMPANY
2016 GENERAL RATE CASE (GRC) PHASE 2 - APPLICATION 15-04-012
CTC REVENUE ALLOCATION - CHAPTER 7 (SHAUGHNESSY)

CTC Allocation by Customer Class

		CURRENT (11/1/2015)		PROPOSED GRC P2				
Line No.	Customer Class (A)	% Allocation (B)	$ Allocation (C)	% Allocation (D)	$ Allocation (E)	$ Change (F)	% Change (G)	Line No.
1	RESIDENTIAL	40.89%	$7,837,705	40.79%	$7,819,092	-$18,613	-0.24%	1
2	SMALL COMMERCIAL	11.61%	$2,225,668	11.29%	$2,163,121	-$62,546	-2.81%	2
3	MEDIUM/LARGE C&I	46.48%	$8,908,586	46.80%	$8,971,122	$62,536	0.70%	3
4	AGRICULTURAL	1.02%	$195,919	1.10%	$211,480	$15,561	7.94%	4
5	LIGHTING	0.00%	$0	0.02%	$3,062	$3,062	NA	5
6	TOTAL	100.00%	$19,167,878	100.00%	$19,167,878	$0	0.00%	6

ATTACHMENT D

Summary of Updates

ATTACHMENT D

SAN DIEGO GAS & ELECTRIC COMPANY
2016 GENERAL RATE CASE (GRC) PHASE 2 - APPLICATION 15-04-012
SUMMARY OF UPDATES FROM APRIL 2015 FILING – CHAPTER 7 (SHAUGHNESSY)

Witness	Location	Update
Jeffrey Shaughnessy	Section I	Removed language regarding SDG&E's 2015 RDW and replaced with reference to TOU proposal in this proceeding.
Jeffrey Shaughnessy	Section II	Removed language regarding SDG&E's 2015 RDW and replaced with reference to TOU proposal in this proceeding.
Jeffrey Shaughnessy	Table JJS-1	Removed information for TOU periods from SDG&E's 2015 RDW and replaced with reference to TOU proposal in this proceeding.
Jeffrey Shaughnessy	Charts JJS-1 and JJS-2	Refreshed graphs for updated 2016 forward prices, correction to 2014 historical prices and added 2015 historical prices.
Jeffrey Shaughnessy	Section III	Updated average annual price per updated 2016 forward prices.
Jeffrey Shaughnessy	Table JJS-2	Removed information from TOU periods in SDG&E's 2015 RDW and replaced with information for TOU periods proposed in this proceeding.
Jeffrey Shaughnessy	Section III	Updated RPS adder based on more recent "Green Value" and average wholesale price.
Jeffrey Shaughnessy	Table JJS-3	Removed information from TOU periods in SDG&E's 2015 RDW and replaced with information for TOU periods proposed in this proceeding.
Jeffrey Shaughnessy	Section IV	Updated $/kW CT cost per updated Final CEC report released March 2015 and updated CAISO report released June 2015.
Jeffrey Shaughnessy	Table JJS-4	Updated $/kW values per updated CEC and CAISO reports.
Jeffrey Shaughnessy	Table JJS-5	Updated information per new LOLE results because of updated hourly load forecast and modified presentation by proposed TOU period instead of hour.
Jeffrey Shaughnessy	Attachment A	Updated per new marginal costs based on proposed TOU periods in this proceeding.
Jeffrey Shaughnessy	Attachment B	Updated per new marginal costs based on proposed TOU periods in this proceeding.
Jeffrey Shaughnessy	Attachment C	Updated because of change in sales forecast.
Jeffrey Shaughnessy	Attachment D	Added.

<u>FIXED COST REPORT - ATTACHMENT D</u>

SDG&E 2016 GRC PHASE 2 MARGINAL COMMODITY COSTS

REBUTTAL TESTIMONY

SDGE

A Sempra Energy utility®

Application of SAN DIEGO GAS & ELECTRIC COMPANY (U 902 E) For Authority To Update Marginal Costs, Cost Allocation, And Electric Rate Design.

Application: 15-04-012
Exhibit No.: SDG&E-16

PREPARED REBUTTAL TESTIMONY OF

JEFFREY J. SHAUGHNESSY

ON BEHALF OF SAN DIEGO GAS & ELECTRIC COMPANY

CHAPTER 6

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF CALIFORNIA

August 30, 2016

TABLE OF CONTENTS

PREPARED REBUTTAL TESTIMONY OF

JEFFREY J. SHAUGHNESSY

(CHAPTER 6)

I. OVERVIEW

The purpose of my testimony is to reply to the opening testimony of the Office of Ratepayer Advocates ("ORA") and Utility Consumers Action Network ("UCAN") regarding marginal commodity costs and allocation, specifically: (1) marginal generation capacity costs ("MGCC") and (2) MGCC allocation. For all of the reasons discussed below, the California Public Utilities Commission ("Commission") should adopt San Diego Gas & Electric Company's ("SDG&E's") marginal commodity cost and allocation proposals, presented in my prepared direct testimony with the updated results presented in this prepared rebuttal testimony.

My rebuttal testimony reaches the following conclusions:

- SDG&E generally agrees with ORA and UCAN's theoretical position that MGCC should be based on an advanced combustion turbine ("CT"), but objects to ORA and UCAN's use of questionable cost data; and
- MGCC allocation to the top 100 hours is a better representation for capacity allocation than using over 2,500 hours.

My rebuttal testimony also provides updated Commodity Revenue Allocation, Equal Percent of Marginal Costs ("EPMC") Commodity rates and Ongoing Competition Transition Charge ("CTC") Revenue Allocation based on: (1) the updated sales forecast presented in the Chapter 4 Rebuttal Testimony of SDG&E witness Schiermeyer, (2) the proposal to include May as a winter month in the Chapter 1 Rebuttal Testimony of SDG&E witness Fang and (3) SDG&E's current effective revenues as of August 1, 2016.

My rebuttal testimony contains the following attachments:

- Attachment A – Updated Commodity Marginal Costs.
- Attachment B – Updated Commodity Revenue Allocations.
- Attachment C – Updated CTC Revenue Allocations.

II. MARGINAL GENERATION CAPACITY COSTS

ORA and UCAN argue that the cost of an advanced CT should be used instead of a conventional CT[1] when determining MGCC. While SDG&E does not dispute ORA and UCAN's theoretical position, based on the stated limits of advanced CT costs in the data source, *California Energy Commission, Estimated Cost of Renewable and Fossil Generation in California (2015)*, their advanced CT data should not be relied on for the purpose of MGCC in this proceeding. On page 3-8 of their testimony, ORA recognizes this issue when it states:

> *However, the CEC report also states in its description of CT plant instant costs, "The advanced CT case cost is based on very limited data for a different advanced gas turbine type."*

But, an even more important quote is from the California Energy Commission ("CEC") report itself on page B-15:

> *The advanced CT case cost is based on very limited data for a different advanced gas turbine type. <u>The significantly lower cost for the advanced CT case seems to overstate the potential</u>*

[1] ORA Direct Testimony June 3, 2016 (Gutierrez) at page 3-6 and UCAN Direct Testimony July 5, 2016 (Jones) at page 3.

> *for economy of scale reduction in cost, particularly since the LMS100 technology requires an increase in auxiliary equipment costs. Therefore, there is a low level of confidence with the advanced CT costs. [Emphasis added]*

For this reason, the advanced CT cost estimate, in which the CEC itself has little confidence, should not be used.

Regarding UCAN's use of the Operations & Maintenance ("O&M") cost estimate from SDG&E's 2012 General Rate Case ("GRC") Phase 2,[2] there is an obvious mismatch in data sources and technologies. The O&M numbers in the CEC report are for the same technology as the installed costs in the report and, therefore, reflect a more accurate representation of the O&M numbers for the respective installed cost numbers. Using the installed cost from the CEC data and O&M costs from SDG&E's 2012 GRC Phase 2 and for a different technology is a clear case of cherry-picking. SDG&E recommends using the conventional CT costs for the MGCC determination, but if the advanced CT costs in the CEC report are used, then the O&M costs also should be for the advanced CT in the CEC report.

III. MARGINAL GENERATION CAPACITY COST ALLOCATION

ORA proposes to allocate capacity to 30% of the hours in a year (2,582 hours) instead of SDG&E's proposed top 100 hours.[3] The total number of hours was based on hours where a relative loss of load event occurred in ORA's modeling; however, it is highly unlikely that there will be a loss of load in that many different hours.

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[2] UCAN Direct Testimony July 5, 2016 (Jones) at page 10.
[3] ORA Direct Testimony June 3, 2016 (Gutierrez) at page 3-18.

If ORA had used top 100 hours of their Loss of Load Expectation ("LOLE") analysis, the results would be very similar to SDG&E's for SDG&E's time-of-use ("TOU") proposal, as seen in Table 1.

Table 1: SDG&E versus ORA[4] MGCC Allocation to Hours

SDG&E TOU Proposal			
	SDG&E *Top 100* Hours	**ORA** *Top 100* Hours	**ORA** *Top 2,582* Hours
Summer			
On-Peak	77%	75%	60%
Off-Peak	23%	24%	27%
Super Off-Peak	0%	0%	1%
Winter			
On-Peak	0%	1%	12%
Off-Peak	0%	0%	0%
Super Off-Peak	0%	0%	0%

More importantly, the hours in which there may be a loss of load are very sensitive to input assumptions, as addressed in the Chapter 3 Rebuttal Testimony of SDG&E witness Anderson. Correcting the data inputs, Mr. Anderson finds the loss of load probability from the ORA modeling results in the LOLE even more concentrated in the on-peak period than SDG&E's MGCC allocation to the highest 100 hours in the LOLE analysis.

IV. UPDATES FROM DIRECT TESTIMONY

My rebuttal testimony also provides updated Commodity Revenue Allocation, EPMC Commodity rates and CTC Revenue Allocation based on the updated sales forecast presented in the Chapter 4 Rebuttal Testimony of SDG&E witness Schiermeyer, the proposal to include May as a winter month in the Chapter 1 Rebuttal Testimony of SDG&E witness Fang and SDG&E's current effective revenues as of August 1, 2016. In addition to the sales update reflected in the CTC allocation, SDG&E is updating the 3-year period used

[4] ORA Workpaper "Errata on 6_20_2016 ORA Testimony Chapter 3 Marginal Generation (Commodity) Capacity Costs Allocation (SDG&E Workpaper).xlsx."

in the calculation of the top 100 hours. In direct testimony, the most-recent three years of available data was 2009-2011. SDG&E has since responded to data requests from ORA[5] and the California Farm Bureau Federation ("Farm Bureau")[6] providing updated information for 2012 and 2013. SDG&E is taking this opportunity to update the CTC allocation with the new, most-recent three years of available data, 2011-2013.

V. CONCLUSION

The Commission should find that SDG&E's proposed marginal commodity costs and resulting allocation are reasonable without modification. The Commission also should find that SDG&E's update to the CTC allocation is reasonable.

This concludes my prepared rebuttal testimony.

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[5] ORA Data Request 3 Response #3.

[6] Farm Bureau Data Request 6 Response #4.

ATTACHMENT A

COMMODITY MARGINAL COSTS

ATTACHMENT A

SAN DIEGO GAS & ELECTRIC COMPANY
2016 GENERAL RATE CASE (GRC) PHASE 2 - APPLICATION 15-04-012
ELECTRIC COMMODITY MARGINAL COSTS AND EPMC RATES & REVENUES, PROPOSED TOU - CHAPTER 6 (SHAUGHNESSY)

Line No.	Description (A)	Unit (B)	Marginal Energy Rate w/ losses (C)	Marginal Capacity Rate w/ losses (D)	Marginal Energy Rate Revenue (E)	Marginal Capacity Rate Revenue (F)	Total Marginal Rate Revenue (G)	EPMC Energy Rate (H)	EPMC Capacity Rate (I)	EPMC Energy Rate Revenue (J)	EPMC Capacity Rate Revenue (K)	Total EPMC Rate Revenue (L)	Line No.
1	**RESIDENTIAL**				$325,943,373	$193,530,976	$519,474,349			$465,820,071	$276,583,665	$742,403,736	1
2	*Secondary*												2
3	**Summer**												3
4	On-Peak Demand	$/kW	0.00	8.63				0.00	12.33				4
5	On-Peak Energy	$/kWh	0.05841	0.00000				0.08347	0.00000				5
6	Off-Peak Energy	$/kWh	0.04849	0.02924				0.06930	0.04179				6
7	Super Off-Peak Energy	$/kWh	0.03963	0.00000				0.05663	0.00000				7
8													8
9	**Winter**												9
10	On-Peak Demand	$/kW	0.00	0.00				0.00	0.00				10
11	On-Peak Energy	$/kWh	0.05275	0.00000				0.07539	0.00000				11
12	Off-Peak Energy	$/kWh	0.04649	0.00000				0.06645	0.00000				12
13	Super Off-Peak Energy	$/kWh	0.03997	0.00000				0.05712	0.00000				13
14													14
15	**SMALL COMMERCIAL**				$104,051,509	$43,618,323	$147,669,832			$148,704,608	$62,336,872	$211,041,479	15
16	*Secondary*												16
17	**Summer**												17
18	On-Peak Demand	$/kW	0.00	7.81				0.00	11.17				18
19	On-Peak Energy	$/kWh	0.05841	0.00000				0.08347	0.00000				19
20	Off-Peak Energy	$/kWh	0.04849	0.02516				0.06930	0.03596				20
21	Super Off-Peak Energy	$/kWh	0.03963	0.00000				0.05663	0.00000				21
22													22
23	**Winter**												23
24	On-Peak Demand	$/kW	0.00	0.00				0.00	0.00				24
25	On-Peak Energy	$/kWh	0.05275	0.00000				0.07539	0.00000				25
26	Off-Peak Energy	$/kWh	0.04649	0.00000				0.06645	0.00000				26
27	Super Off-Peak Energy	$/kWh	0.03997	0.00000				0.05712	0.00000				27
28													28
29	*Primary*												29
30	**Summer**												30
31	On-Peak Demand	$/kW	0.00	7.78				0.00	11.11				31
32	On-Peak Energy	$/kWh	0.05812	0.00000				0.08307	0.00000				32
33	Off-Peak Energy	$/kWh	0.04827	0.02505				0.06898	0.03579				33
34	Super Off-Peak Energy	$/kWh	0.03950	0.00000				0.05646	0.00000				34
35													35
36	**Winter**												36
37	On-Peak Demand	$/kW	0.00	0.00				0.00	0.00				37
38	On-Peak Energy	$/kWh	0.05251	0.00000				0.07504	0.00000				38
39	Off-Peak Energy	$/kWh	0.04630	0.00000				0.06617	0.00000				39
40	Super Off-Peak Energy	$/kWh	0.03985	0.00000				0.05695	0.00000				40

ATTACHMENT A

SAN DIEGO GAS & ELECTRIC COMPANY
2016 GENERAL RATE CASE (GRC) PHASE 2 - APPLICATION 15-04-012
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1	**MEDIUM & LARGE COMMERCIAL/INDUSTRIAL**				$309,737,034	$121,552,096	$431,289,130			$442,658,876	$173,715,469	$616,374,345	1
2	*Secondary*												2
3	**Summer**												3
4	On-Peak Demand	$/kW	0.00	11.79				0.00	16.85				4
5	On-Peak Energy	$/kWh	0.05841	0.00000				0.08347	0.00000				5
6	Off-Peak Energy	$/kWh	0.04849	0.02191				0.06930	0.03131				6
7	Super Off-Peak Energy	$/kWh	0.03963	0.00000				0.05663	0.00000				7
8													8
9	**Winter**												9
10	On-Peak Demand	$/kW	0.00	0.00				0.00	0.00				10
11	On-Peak Energy	$/kWh	0.05275	0.00000				0.07539	0.00000				11
12	Off-Peak Energy	$/kWh	0.04649	0.00000				0.06645	0.00000				12
13	Super Off-Peak Energy	$/kWh	0.03997	0.00000				0.05712	0.00000				13
14													14
15	*Primary*												15
16	**Summer**												16
17	On-Peak Demand	$/kW	0.00	11.74				0.00	16.77				17
18	On-Peak Energy	$/kWh	0.05812	0.00000				0.08307	0.00000				18
19	Off-Peak Energy	$/kWh	0.04827	0.02181				0.06898	0.03117				19
20	Super Off-Peak Energy	$/kWh	0.03950	0.00000				0.05646	0.00000				20
21													21
22	**Winter**												22
23	On-Peak Demand	$/kW	0.00	0.00				0.00	0.00				23
24	On-Peak Energy	$/kWh	0.05251	0.00000				0.07504	0.00000				24
25	Off-Peak Energy	$/kWh	0.04630	0.00000				0.06617	0.00000				25
26	Super Off-Peak Energy	$/kWh	0.03985	0.00000				0.05695	0.00000				26
27													27
28	*Transmission*												28
29	**Summer**												29
30	On-Peak Demand	$/kW	0.00	11.23				0.00	16.05				30
31	On-Peak Energy	$/kWh	0.05563	0.00000				0.07951	0.00000				31
32	Off-Peak Energy	$/kWh	0.04621	0.02088				0.06605	0.02984				32
33	Super Off-Peak Energy	$/kWh	0.03792	0.00000				0.05419	0.00000				33
34													34
35	**Winter**												35
36	On-Peak Demand	$/kW	0.00	0.00				0.00	0.00				36
37	On-Peak Energy	$/kWh	0.05030	0.00000				0.07188	0.00000				37
38	Off-Peak Energy	$/kWh	0.04440	0.00000				0.06345	0.00000				38
39	Super Off-Peak Energy	$/kWh	0.03825	0.00000				0.05466	0.00000				39

ATTACHMENT A

SAN DIEGO GAS & ELECTRIC COMPANY
2016 GENERAL RATE CASE (GRC) PHASE 2 - APPLICATION 15-04-012
ELECTRIC COMMODITY MARGINAL COSTS AND EPMC RATES & REVENUES, PROPOSED TOU - CHAPTER 6 (SHAUGHNESSY)

Line No.	Description (A)	Unit (B)	Marginal Energy Rate w/ losses (C)	Marginal Capacity Rate w/ losses (D)	Marginal Energy Rate Revenue (E)	Marginal Capacity Rate Revenue (F)	Total Marginal Rate Revenue (G)	EPMC Energy Rate (H)	EPMC Capacity Rate (I)	EPMC Energy Rate Revenue (J)	EPMC Capacity Rate Revenue (K)	Total EPMC Rate Revenue (L)	Line No.
1	**AGRICULTURE**				$12,923,717	$4,241,400	$17,165,117			$18,469,854	$6,061,572	$24,531,426	1
2	*Secondary*												2
3	**Summer**												3
4	On-Peak Demand	$/kW	0.00	6.78				0.00	9.68				4
5	On-Peak Energy	$/kWh	0.05841	0.00000				0.08347	0.00000				5
6	Off-Peak Energy	$/kWh	0.04849	0.01608				0.06930	0.02298				6
7	Super Off-Peak Energy	$/kWh	0.03963	0.00000				0.05663	0.00000				7
8													8
9	**Winter**												9
10	On-Peak Demand	$/kW	0.00	0.00				0.00	0.00				10
11	On-Peak Energy	$/kWh	0.05275	0.00000				0.07539	0.00000				11
12	Off-Peak Energy	$/kWh	0.04649	0.00000				0.06645	0.00000				12
13	Super Off-Peak Energy	$/kWh	0.03997	0.00000				0.05712	0.00000				13
14													14
15	*Primary*												15
16	**Summer**												16
17	On-Peak Demand	$/kW	0.00	6.74				0.00	9.64				17
18	On-Peak Energy	$/kWh	0.05812	0.00000				0.08307	0.00000				18
19	Off-Peak Energy	$/kWh	0.04827	0.01600				0.06898	0.02287				19
20	Super Off-Peak Energy	$/kWh	0.03950	0.00000				0.05646	0.00000				20
21													21
22	**Winter**												22
23	On-Peak Demand	$/kW	0.00	0.00				0.00	0.00				23
24	On-Peak Energy	$/kWh	0.05251	0.00000				0.07504	0.00000				24
25	Off-Peak Energy	$/kWh	0.04630	0.00000				0.06617	0.00000				25
26	Super Off-Peak Energy	$/kWh	0.03985	0.00000				0.05695	0.00000				26
27													27
28	**LIGHTING**				$3,950,348	$1,269,403	$5,219,751			$5,645,617	$1,814,160	$7,459,777	28
29	*Secondary*												29
30	**Summer**												30
31	On-Peak Demand	$/kW	0.00	11.20				0.00	16.01				31
32	On-Peak Energy	$/kWh	0.05841	0.00000				0.08347	0.00000				32
33	Off-Peak Energy	$/kWh	0.04849	0.01222				0.06930	0.01746				33
34	Super Off-Peak Energy	$/kWh	0.03963	0.00000				0.05663	0.00000				34
35													35
36	**Winter**												36
37	On-Peak Demand	$/kW	0.00	0.00				0.00	0.00				37
38	On-Peak Energy	$/kWh	0.05275	0.00000				0.07539	0.00000				38
39	Off-Peak Energy	$/kWh	0.04649	0.00000				0.06645	0.00000				39
40	Super Off-Peak Energy	$/kWh	0.03997	0.00000				0.05712	0.00000				40
41													41
42	**TOTAL RATE REVENUE SUMMARY**												42
43													43
44	**RESIDENTIAL**				$325,943,373	$193,530,976	$519,474,349			$465,820,071	$276,583,665	$742,403,736	44
45	**SMALL COMMERCIAL**				$104,051,509	$43,618,323	$147,669,832			$148,704,608	$62,336,872	$211,041,479	45
46	**MEDIUM/LARGE C&I**				$309,737,034	$121,552,096	$431,289,130			$442,658,876	$173,715,469	$616,374,345	46
47	**AGRICULTURAL**				$12,923,717	$4,241,400	$17,165,117			$18,469,854	$6,061,572	$24,531,426	47
48	**LIGHTING**				$3,950,348	$1,269,403	$5,219,751			$5,645,617	$1,814,160	$7,459,777	48
49	**TOTAL**				$756,605,981	$364,212,197	$1,120,818,179			$1,081,299,026	$520,511,738	$1,601,810,764	49

ATTACHMENT B

COMMODITY REVENUE ALLOCATIONS

ATTACHMENT B.1

SAN DIEGO GAS & ELECTRIC COMPANY
2016 GENERAL RATE CASE (GRC) PHASE 2 - APPLICATION 15-04-012
ELECTRIC COMMODITY REVENUE ALLOCATION - CHAPTER 6 (SHAUGHNESSY)

Commodity Marginal Cost Allocation by Customer Class

		PROPOSED GRC P2 (PROPOSED TOU)				
		MARGINAL ENERGY COSTS		MARGINAL CAPACITY COSTS		
Line No.	Customer Class (A)	% Allocation (B)	$ Allocation (C)	% Allocation (D)	$ Allocation (E)	Line No.
1	RESIDENTIAL	43.08%	$325,943,373	53.14%	$193,530,976	1
2	SMALL COMMERCIAL	13.75%	$104,051,509	11.98%	$43,618,323	2
3	MEDIUM/LARGE C&I	40.94%	$309,737,034	33.37%	$121,552,096	3
4	AGRICULTURAL	1.71%	$12,923,717	1.16%	$4,241,400	4
5	LIGHTING	0.52%	$3,950,348	0.35%	$1,269,403	5
6	TOTAL	100.00%	$756,605,981	100.00%	$364,212,197	6

ATTACHMENT B.2

SAN DIEGO GAS & ELECTRIC COMPANY
2016 GENERAL RATE CASE (GRC) PHASE 2 - APPLICATION 15-04-012
ELECTRIC COMMODITY REVENUE ALLOCATION - CHAPTER 6 (SHAUGHNESSY)

Commodity Allocation by Customer Class

		CURRENT (8/1/2016)		PROPOSED GRC P2 (PROPOSED TOU)				
Line No.	Customer Class (A)	% Allocation (B)	$ Allocation (C)	% Allocation (D)	$ Allocation (E)	$ Change (F)	% Change (G)	Line No.
1	RESIDENTIAL	45.69%	$731,829,343	46.35%	$742,403,736	$10,574,393	1.44%	1
2	SMALL COMMERCIAL	11.34%	$181,589,939	13.18%	$211,041,479	$29,451,540	16.22%	2
3	MEDIUM/LARGE C&I	41.02%	$657,089,523	38.48%	$616,374,345	-$40,715,178	-6.20%	3
4	AGRICULTURAL	1.53%	$24,507,408	1.53%	$24,531,426	$24,018	0.10%	4
5	LIGHTING	0.42%	$6,794,551	0.47%	$7,459,777	$665,226	9.79%	5
6	TOTAL	100.00%	$1,601,810,764	100.00%	$1,601,810,764	$0	0.00%	6

ATTACHMENT C

CTC REVENUE ALLOCATIONS

ATTACHMENT C

SAN DIEGO GAS & ELECTRIC COMPANY
2016 GENERAL RATE CASE (GRC) PHASE 2 - APPLICATION 15-04-012
CTC REVENUE ALLOCATION - CHAPTER 6 (SHAUGHNESSY)

CTC Allocation by Customer Class

		CURRENT (8/1/2016)		PROPOSED GRC P2				
Line No.	Customer Class (A)	% Allocation (B)	$ Allocation (C)	% Allocation (D)	$ Allocation (E)	$ Change (F)	% Change (G)	Line No.
1	RESIDENTIAL	40.89%	$13,410,954	38.55%	$12,644,627	-$766,327	-5.71%	1
2	SMALL COMMERCIAL	11.61%	$3,808,299	12.56%	$4,121,004	$312,705	8.21%	2
3	MEDIUM/LARGE C&I	46.48%	$15,243,319	47.79%	$15,673,653	$430,334	2.82%	3
4	AGRICULTURAL	1.02%	$335,233	1.06%	$348,273	$13,040	3.89%	4
5	LIGHTING	0.00%	$0	0.03%	$10,248	$10,248	NA	5
6	TOTAL	100.00%	$32,797,805	100.00%	$32,797,805	$0	0.00%	6

<u>FIXED COST REPORT - ATTACHMENT E</u>

INFORMATION REQUESTED IN SEPTEMBER 22, 2016 ALJ RULING

ATTACHMENT E

SDG&E responsive detail to the ALJ's September 22, 2016 email Ruling Requirements (3) and (4)

ALJ Requirements:

(3) All three utilities should include information linking proposed fixed cost and fixed charge calculation to the GRC Phase 1 testimony or other applicable proceeding.

(4) For data requests related to fixed cost and fixed charge calculations, each IOU should cite and link to GRC Phase 1 testimony or work papers. If requested, workpapers must be provided in Excel format. Workpapers provided to Energy Division staff must be in Excel format. The source of each number must be cited and described.

SDG&E Response to Requirement 3:

SDG&E's 2016 GRC Phase 1 proceeding (A.14-11-003) forecasts the total costs in Test Year (TY) 2016 to provide safe and reliable electric service to customers, including complying with governmental regulation. SDG&E's 2016 GRC Phase 2 proceeding (A.15-04-012) forecasts the marginal distribution customer costs to provide an individual customer access to electric service based on the customer type, size, service voltage, and type of equipment. As explained below, the GRC Phase 2 marginal costs include some of the GRC Phase 1 proposed cost items but, in general, the GRC Phase 2 marginal costs are developed separately from the GRC Phase 1 because Phase 2 develops customer specific costs.

The 2016 GRC Phase 2 marginal distribution customer costs are composed of two types of costs:

A) The first set of marginal distribution customer costs is associated with the investment required to provide access (hook up) to a new customer, which reflect transformer, service and meter ("TSM") costs. These costs are developed based on 2013 material and labor costs to install each type of TSM asset by customer type, size, and service voltage, with the costs fully loaded and escalated into 2016 dollars. The loaders consist of General Plant, Working Capital, and Administrative & General (A&G) Non-Plant Operations & Maintenance (O&M). The General Plant and A&G Non-Plant O&M loaders are developed based on a five-year average (2009-2013) of SDG&E recorded costs. The Working Capital loader is developed based on 2013 recorded weighted-average depreciated rate based presented in SDG&E's 2016 GRC Phase 1 proceeding. The 2013 TSM costs and loaders are escalated into 2016 dollars using the escalation factors proposed in SDG&E's 2016 GRC Phase 1 proceeding. Finally, the fully loaded TSM costs are adjusted for a Miscellaneous Revenues O&M Offset, as proposed by UCAN in their direct testimony and agreed to by SDG&E in its rebuttal testimony, that is based on TY 2016 miscellaneous revenues proposed in SDG&E's 2016 GRC Phase 1 proceeding.

B) The second set of marginal distribution customer costs is associated with the ongoing costs of maintaining the new customer, which consists of TSM O&M and Customer Service costs. The TSM O&M costs are developed based on SDG&E 2013 historical distribution O&M costs, with these costs allocated between customer-related and demand-related distribution costs based on a five-year average (2009-2013) of SDG&E historical O&M costs. The Customer Service costs are developed based on adjusted-recorded 2013 costs submitted in SDG&E's 2016 GRC Phase 1 proceeding. The 2013 TSM O&M and Customer Service costs are then escalated into 2016 dollars based on the escalation factors proposed in SDG&E's 2016 GRC Phase 1 proceeding.

SDG&E Response to Requirement 4:

Below are the link cites in SDG&E's 2016 GRC Phase 2 marginal distribution customer cost rebuttal testimony and workpapers that can be used to access SDG&E 2016 GRC Phase 1 testimony/workpapers:

A) **2016 GRC Phase 2 Marginal Customer Cost Workpaper –** the "Input" tab in SDG&E's "2016 GRC P2 Marg Cust Costs (Chapter 5 Rebuttal Workpaper).xlsx" workpaper file links to the following SDG&E 2016 GRC Phase 1 (A.14-11-003) direct testimony and/or workpapers in the development of SDG&E's proposed 2016 marginal distribution customer costs:

   - Footnote 2 - Working Capital Loading Factor: is the net working capital loading factor based on 2013 expenses from the Direct Testimony of Jesse S. Aragon, Exhibit SDG&E-27, Table SDG&E JSA-1 in SDG&E's TY 2016 GRC Phase 1 (A.14-11-003).

   - Footnote 5 - 2016 TSM Escalator: from the Direct Testimony workpapers of Scott R. Wilder, Exhibit SDG&E-33, in SDG&E's TY 2016 GRC Phase 1 (A.14-11-003).

   - Footnote 6 - 2016 O&M Escalator: from the Direct Testimony workpapers of Scott R. Wilder, Exhibit SDG&E-33, in SDG&E's TY 2016 GRC Phase 1 (A.14-11-003).

   - Footnote 7 - 2016 Customer Services Escalator: from the Direct Testimony workpapers of Scott R. Wilder, Exhibit SDG&E-33, in SDG&E's TY 2016 GRC Phase 1 (A.14-11-003).

   - Footnote 8 – Miscellaneous Revenues O&M Offset: from UCAN's 2016 GRC Phase 2 Direct Testimony, which is based on the TY 2016 miscellaneous revenues proposed in the Direct Testimony of Michelle A. Somerville, Exhibit SDG&E-34, in SDG&E's TY 2016 GRC Phase 1 (A.14-11-003).

B) **Customer Services Cost Study –** Attachment C of SDG&E's 2016 GRC Phase 2 Chapter 6 Direct Testimony presents SDG&E's Customer Services Cost Study. Footnote 3 on page 1 of Attachment C states that these costs are based on 2013 Adjusted-Recorded Customer Services Electric Distribution Costs identified in SDG&E TY 2016 GRC Phase 1 (A.14-10-003) Direct Testimony of Khai Nguyen, Exhibit SDG&E-36, p. KN-A-31, Table KN-30. The Customer Services costs presented in Attachment C are used in the "Cust Service Cost Allocations" tab of SDG&E's "2016 GRC P2 Marg Cust Costs (Chapter 5 Rebuttal Workpaper).xlsx" workpaper file to develop SDG&E's proposed 2016 marginal distribution customer costs.

WORKSHOP MATERIALS

Residential Fixed Charge Workshop

October 13, 2016

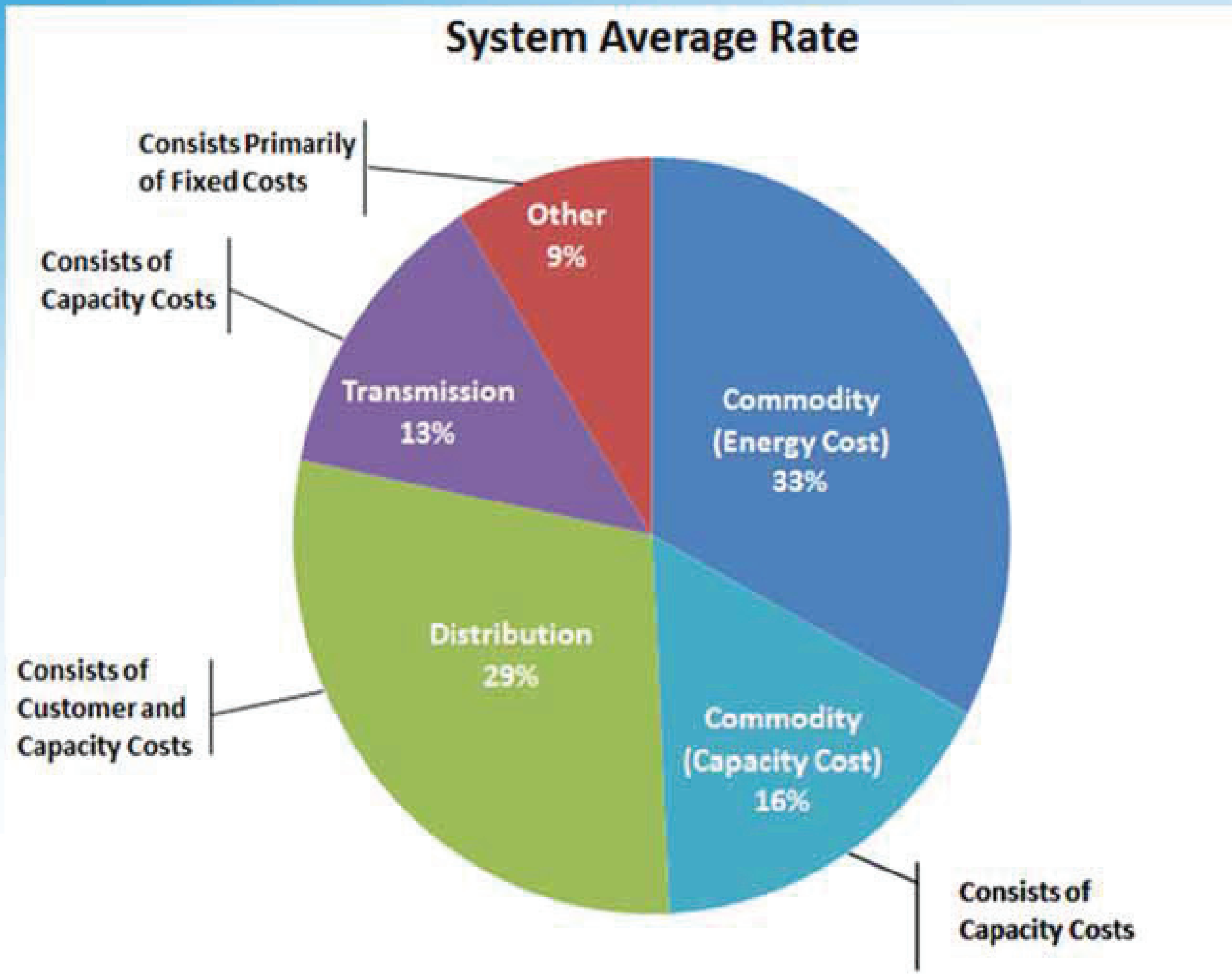
Definition of Eligible Costs – AB 327

- **AB 327 defines fixed charges as the following:**

  "Fixed charge" means any fixed customer charge, basic service fee, demand differentiated basic service fee, demand charge, *or other charge not based upon the volume of electricity consumed*.

  – Pub. Util. Code Section 739.9. (emphasis added).

Definition of Eligible Costs – by Cost Category



- Only 1/3 of the total utility cost of service is related to the kWh energy usage of customers.
- Nearly 100% of costs for residential customers recovered through kWh energy rates.

Definition of Eligible Costs – by Cost Category

Marginal Costs:

- **Customer Costs:** These costs are independent of a customer's level of energy use and are required for each interconnected customer; therefore, customer costs should be recovered in a fixed or monthly charges ($/month). These costs include account set-up costs, billing and payment, credits and collections, customer contact, and metering services.

- **Energy Costs:** These costs are incurred on a variable basis (based on energy usage) with costs dependent on the time of delivery.

- **Capacity-related Costs:** These costs include Generation Capacity costs, Distribution Demand costs and Transmissions costs.

Non-bypassable Costs: Transmission charge, Public Purpose Program Charge, Nuclear Decommissioning Charge, Competition Transition Charge, New System Generation Charge , Department of Water Resources Bond Charge, and the Power Cost Indifference Amount applicable only to DA and CCA customers (D.13-10-019).

Definition of Eligible Costs – by Cost Category

(A)	(B)	(C)	(D)	(E)	(F)=(C)+(D)+(E)	(G)=(B)-(F)	H	(I)=(C)+(D)+(G)
		Marginal Costs***				Additional Costs		
Residential[1]	Revenue Requirement ($ million)	Customer-Related ($ million)	Capacity-Related ($ million)	Energy-Related ($ million)	Total Marginal Cost ($ million)	Additional Fixed Costs ($ million)^	Additional Energy Costs ($ million)	Total Fixed Costs ($ million)
Distribution*	$644.8	$312.4	$302.5	$0	$614.9	$29.9	$0	$644.8
Commodity*	$730.6	$0	$272.6	$459.2	$731.8	-$1.3	$0	$271.4
Transmission****	$220.7	$0	$220.7	$0	$220.7	$0	$0	$220.7
PPP	$92.7	$0	$0	$0	$0	$92.7	$0	$92.7
All other NBC	$1.0	$0	$0	$0	$0	$1.0	$0	$1.0
TRAC	$127.5	$0	$0	$0	$0	$0	$127.5	$0
Total	$1,817.3	$312.4	$795.9	$459.2	$1,567.5	$122.3	$127.5	$1,230.6
$/cust-mo**	$118.97	$20.44	$52.10	$30.09	$102.62	$8.00	$8.34	$80.54

[1]Revenues are unadjusted class averages.

*Distribution and EECC marginal costs are EPMC-adjusted.

**$/cust-mo: Calculated by adding EECC divided by bundled customer-months and all other rate components by system customer-months.

***EPMC-adjusted marginal customer costs differ from Table 2 as Table 3 is based on customer-months and number of customers in the GRC P2 rebuttal testimony of William Saxe.

****Includes Reliability Services (RS)

^Additional fixed costs in Distribution represent CSI, DR and SGIP costs. Additional fixed costs in EECC represent the DWR-BC credit.

Cost Study Methodologies - Distribution

- <u>Distribution Customer-related Costs</u>

  Cost of providing an individual customer access to electrical service consisting of:

  a) Costs associated with the investment required to provide access (hook up) to a new customer that consist of transformers, services, meters (TSM), and applicable loaders.
  b) Ongoing costs of maintaining the new customer such as Customer-Related O&M and Customer Services costs.

  SDG&E proposes that marginal distribution customer costs are calculated based on the Rental Method.

- <u>Distribution Demand-related Costs</u>

  Costs of providing facilities from the substation to the customer access point in order to meet the customer's individual demands consisting of:

  a) Feeder & Local Distribution Costs and applicable loaders.
  b) Substation Costs and applicable loaders.

  SDG&E proposes that marginal distribution demand costs are calculated based on the NERA Regression Method where the distribution demand costs are regressed over SDG&E's distribution planning forecasted distribution loads over the 2002-2016 period.

Cost Study Methodologies - Commodity

- **Commodity Energy-Related Costs:**
  - Marginal energy costs (“MEC”) are the added energy costs incurred to meet electricity consumption.
  - MEC are the projected energy costs incurred to meet electricity consumption. Since SDG&E transacts in the California Independent System Operator (“CAISO”) markets, the marginal energy costs are based on monthly electric forward market prices specific to South Path-15 (“SP-15”) and an annual hourly profile of electricity prices representative of the San Diego area. A Renewable Portfolio Standard (“RPS”) adder is also included since added load requires added renewable energy under the RPS.
- **Commodity Demand-Related Costs**
  - Marginal generation capacity costs (“MGCC”) relate to the added costs incurred to meet electric demand.
  - MGCC are calculated based on long-term considerations and are based on the net cost of new entry of a combustion turbine (“CT”), the long-term cost of adding new capacity. This amount is equal to the fixed costs of a CT less expected profits from energy and ancillary service markets.

SDG&E's Proposal

SDGE
A Sempra Energy utility®

- SDG&E's proposal for *eligible* costs to be recovered in a residential fixed charge is to include all costs that do not vary with customer's consumption regardless of function, which includes:
  - **Distribution costs** including both customer-related and capacity-related distribution costs,
  - **Commodity capacity-related costs** and
  - **Non-bypassable charges** broadly defined as Transmission charge, Public Purpose Program Charge, Nuclear Decommissioning Charge, Competition Transition Charge, New System Generation Charge, Department of Water Resources Bond Charge, and the Power Cost Indifference Amount applicable only to DA and CCA customers.
- SDG&E proposes the **Rental Method** for determining the marginal distribution customer costs
- SDG&E proposes the **NERA Regression Method** for determining the marginal distribution demand costs